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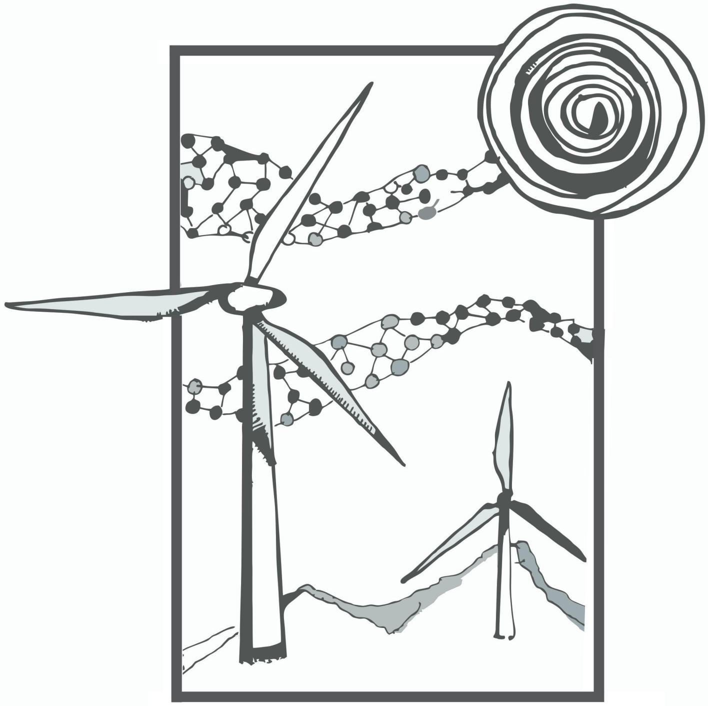
Coordination of Flexibility Contracting in Wholesale and Local Electricity Markets



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Dissertation presented in partial fulfillment of the requirements for the degree of Doctor of Engineering Science (PhD): Electrical Engineering

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Abstract

Energy users are investing in solar panels, batteries and smart-home energy systems. New technology is creating both new opportunities and new needs. New opportunities arise when users are empowered to respond to market signals. New needs arise when network topology is transforming. Decentralized renewable energy, electric vehicles, and storage are changing the face of electricity distribution networks. Taking advantage of new opportunities means opening the market to all participants. Making the best use of decentralized resources means identifying decentralized network needs and constraints. This dissertation is divided into two main parts to study the coordination of demand response -user participation- procurement. The first part studies the integration of demand response into the wholesale market design. The second part analyses local network needs and studies how user participation can be coordinated to provide local flexibility services.

The integration of demand response into the wholesale electricity market is studied in Part I of the thesis. Demand response needs to be aggregated to make a difference at a wholesale market level. The aggregation of demand poses challenges to market design regarding interactions between actors, procurement procedures and remuneration mechanisms. What's more, aggregation has effects on current market participants. The aggregator trades flexibility provided by consumers who already have contracts with retailers. These retailers foresee needs of their customers and trade energy accordingly. When a third party, the aggregator, is also making decisions on their forecasted load, conflicts arise. The exact nature of these conflicts is explored in detail. It is found that when consumers are asked to modify their consumption patterns at one hour, they are likely to make up for it at a later hour. This is defined as the rebound effect. Aggregators impact balancing responsible parties (BRPs) on two main levels: market profits and retail profits. Proposals for transfer payments from the aggregator to the BRP to solve these conflicts are modelled using an empirical approach. The BRP is modelled as a portfolio owner of generation and load. The aggregator supplies demand response flexibility to the market during the best possible hours as a result of an optimization. It is found that demand response will be deployed as long as the transfer payment is less than the peak and off-peak market price. Demand response has an arbitraging effect in the market therefore can be profitable for the party attributed balancing responsibility.

Part II of the dissertation is aimed at reaping the possibilities of demand response at a local level. While the focus of Part I is geared towards wholesale market benefits, the focus of Part II is in using flexibility to deal with grid issues and avoid network reinforcements. It is found in current literature and ongoing projects that there is no consensus on a framework design for the procurement of local flexibility. The transmission system operator, the distribution system operator (DSO), an independent aggregator, and a third party actor have all been proposed as local market operators. A method is proposed to analyze the need that can be fulfilled by local flexibility in the distribution system. Demand and price criteria for flexibility services are defined from the point of view of the DSO. The value of flexibility to the DSO is defined by an analysis of the savings achieved by avoiding grid reinforcements. Congestion in the distribution grid is chosen a use-case to test the methodology.

A first case is studied where the DSO procures flexibility directly at cost-value in order to avoid network reinforcements. It is found that flexibility use can save up to two thirds of the cost of grid reinforcements for the DSO compared to the case without flexibility. A second case is studied where a profit maximizing making aggregator is introduced. In this case, the DSO competes with a BRP for the flexibility resources that would solve its problems in the grid. A quantity demanded and a valuation of flexibility for the BRP is proposed. The BRP needs flexibility to cover deviations in its short term to intraday renewable energy profiles. The BRP is willing to pay for flexibility as long as it costs less than the balancing penalties it would otherwise incur. The two actors, DSO and BRP, have different decision horizons. The DSO needs to make a decision to buy flexibility or reinforce the network in advance, while the BRP needs flexibility on an almost real-time horizon. The aggregator needs to make the decision of who to sell to in advance, so the market is bilaterally organized. It is shown that as the DSO's willingness to pay is higher than the BRP's most of the time, so it wins the bid for most of the available flexibility with respect to the BRP. There is still a long way to travel for users to deliberately affect the functioning of electricity markets and grids. This dissertation opens up a discussion on a whole scale and a local level in an effort to exploit different possible uses of flexibility.

Beknopte Samenvatting

Energiegebruikers investeren in zonnepanelen, batterijen en smart-home energiemanagement systemen. De opkomst van nieuwe technologieën creëert zowel opportuniteiten als uitdagingen. Opportuniteiten ontstaan waar eindgebruikers de mogelijkheid hebben om in te spelen op marktsignalen. Nieuwe noden ontstaan dan weer wanneer elektriciteitsnetten bijvoorbeeld een wijziging in topologie ondergaan. Gedistribueerde hernieuwbare energiebronnen, elektrische voertuigen and energieopslag hebben een impact op distributienetten. Het volledig benutten van nieuwe opportuniteiten vereist dat eindgebruikers toegang hebben tot de elektriciteitsmarkt. Optimaal gebruik van gedistribueerde energiebronnen veronderstelt daarenboven het in kaart brengen van de noden en beperkingen van distributienetten. Deze thesis behandelt vraagstukken met betrekking tot de coördinatie van de aankoop van vraagrespons en is ingedeeld in twee grote delen. Het eerste deel focust op de integratie van vraagrespons in de groothandelsmarkt ("wholesale market") voor elektriciteit. In het tweede deel worden de lokale noden van elektriciteitsnetten bestudeerd en wordt geanalyseerd hoe eindgebruikers op een gecoördineerde manier lokale flexibiliteitsdiensten kunnen aanbieden.

Deel 1 van de thesis focust op de integratie van vraagrespons in de groothandelsmarkt voor elektriciteit. Vraagrespons dient geaggregeerd te worden om een verschil te maken op de groothandelsmarkt. Die aggregatie van flexibele vraag leidt tot uitdagingen voor het ontwerp van de elektriciteitsmarkt, meer bepaald wat betreft de precieze interacties tussen actoren, aankoopprocedures en vergoedingen. Bovendien heeft aggregatie ook effecten op de huidige marktspelers. Een aggregator verhandelt flexibiliteit van eindgebruikers die reeds een bestaand contract hebben met energieleveranciers. Die laatste voorspellen de energienoden van hun klanten en handelen ernaar op de markt. Wanneer een derde partij, in dit geval een aggregator, eveneens beslissingen neemt op basis van voorspeld verbruik, kunnen conflicten ontstaan. De onderliggende mechanismen van deze conflicten worden in detail belicht. Eén van de bevindingen is dat wanneer eindgebruikers hun consumptiepatroon flexibel aanpassen in een

bepaald uur, ze dit meer dan waarschijnlijk compenseren op een later tijdstip ("rebound" effect). Acties van aggregatoren beïnvloeden de inkomsten van evenwichtsverantwoordelijken (balancing responsible parties of BRPs) op twee niveaus: Inkomsten gegenereerd uit activiteiten op de groothandelsmarkt en inkomsten uit retail activiteiten.

Mogelijke compensatievergoedingen tussen een aggregator en de BRP van de eindgebruiker, worden via een empirische benadering gemodelleerd. De evenwichtsverantwoordelijke is gemodelleerd als een eigenaar van een portfolio bestaande uit zowel elektriciteitsopwekking als verbruik. Het model optimaliseert de activering van vraagrespons door een aggregator naar de best mogelijke momenten. Hieruit blijkt dat vraagrespons ingezet wordt zolang de compensatievergoeding lager is dan de piek en dal marktprijzen. Vraagrespons leidt tot een arbitrage-effect in de elektriciteitsmarkt en kan daarom voordelig zijn voor een partij met evenwichtsverantwoordelijkheid.

Deel 2 van de thesis focust op de mogelijkheden die vraagrespons bieden op lokaal niveau. In deel 1 kwamen vooral de voordelen op de groothandelsmarkt aan bod, terwijl in deel 2 flexibiliteit ingezet wordt voor het oplossen van lokale netproblemen en het vermijden van investeringen in het elektriciteitsnet. Noch in literatuur, noch in lopende projecten werd een consensus gevonden voor een ideaal kader voor de aankoop en inzet van lokale flexibiliteit. De transmissienetbeheerder (TNB), de distributienetbeheerder (DNB), een onafhankelijke aggregator en een derde partij zijn mogelijke actoren die de rol van lokale markt operator kunnen opnemen. Deze thesis stelt een methode voor om te analyseren welke noden door lokale flexibiliteit in het distributienet opgelost kunnen worden. Criteria voor de vraag naar en de prijs van flexibiliteitsdiensten worden gedefinieerd vanuit het standpunt van een DNB. De waarde van flexibiliteit voor een DNB wordt bepaald door een analyse van de besparingen gerealiseerd door het vermijden van netinvesteringen. De methodologie werd getest aan de hand van een use case met betrekking tot congestie in een distributienet.

In een eerste gevalstudie, koopt de DNB rechtstreeks flexibiliteit op aan de reële kost met het oog op het vermijden van netinvesteringen. Hieruit blijkt dat het gebruik van flexibiliteit kan leiden tot 2/3 kostenbesparingen in vergelijking met traditionele netinvesteringen. Een tweede gevalstudie richt zich op een aggregator die zijn winsten maximaliseert. In dit geval concurreert een DNB met een BRP om flexibiliteit te bekomen voor het oplossen van netproblemen. De vraag naar en waardering van flexibiliteit voor een BRP worden behandeld. De BRP heeft nood aan flexibiliteit om afwijkingen van voorspelde hernieuwbare energieproductie op te vangen. Als gevolg hiervan, is een BRP bereid te betalen voor flexibiliteit zolang de kost lager is dan de onbalanskosten. De DNB en de BRP hebben echter een verschillende tijdshorizon voor het nemen van beslissingen. Een DNB moet op voorhand beslissen flexibiliteit aan te kopen of het distributienet te versterken, terwijl een BRP flexibiliteit bijna real time nodig heeft. Een aggregator moet bijgevolg beslissen aan wie hij vooraf bilateraal flexibiliteit verkoopt. Uit de analyse blijkt dat de betalingsbereidheid van DNBs in de meeste gevallen groter is dan BRPs. Er is nog een lange weg te gaan voor eindgebruikers om effectief en doelbewust invloed te hebben op elektriciteitsmarkten en netten. Deze thesis geeft inzichten voor verschillende exploitatiemogelijkheden van flexibiliteit, zowel op het niveau van groothandelsmarkten als op lokaal niveau.

Acknowledgements

Discover yourself. Start with the world. The slogan of the KU Leuven. I think it accurately describes my past few years in Leuven. It has been a journey of self discovery through knowledge. My time as a PhD researcher is coming to an end, but my time as a researcher at life is just now starting.

I am grateful to my promoter Ronnie Belmans for supporting me through the life changing opportunity to complete a PhD at Electa, at EnergyVille and at VITO. The unique collaboration between research institutes has been the backdrop of my work. I would like to thank VITO for sponsoring my research, and specifically Daan Six for making me a part of the e-markets team. You add enthusiasm and team spirit to e-marketeers. Also at the VITO side, Virginia Gómez was an unwavering and ever-patient support throughout these years. Thank you also to Cedric, my advisor from the Electa side, for giving me space to develop my own ideas.

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Warm Regards,

Ariana
Leuven, May 2017

“We put thirty spokes together and call it a wheel,
But it is on the space where there is nothing that the usefulness of the wheel depends.

We turn clay to make a vessel,
But it is on the space where there is nothing that the usefulness of the vessel depends.

We pierce doors and windows to make a house,
And it is on these spaces where there is nothing that the usefulness of the house depends.

Therefore just as we take advantage of what is, we should recognize the usefulness of what is not.”

- Lao Tze, Tao Te Ching

Abbreviations

BRP	balancing responsible party
CHP	combined heat and power
cVPP	commercial virtual power plant
DA	day ahead
DER	distributed energy resources
DG	distributed generation
DR	demand response
DSO	distribution system operator
EC	European Commission
EV	electric vehicle
FERC	Federal Energy Regulatory Commission
FSP	flexibility service provider
ICT	information and communications technology
LMP	locational marginal price
MC	marginal cost
MP	marginal price
NEBEF	Notification d'Echanges de Blocs d'Effacement
PV	photovoltaic
RES	Renewable Energy Sources
RTM	real-time markets

TSO	transmission system operator
tVPP	technical virtual power plant
VPP	virtual power lant

List of Symbols

ag	aggregator
$AGGMAX_t$	aggregator's limit for available flexibility at time t [MWh]
BEN_{DSO}	benefit of using flexibility for the DSO [€]
b_n	price benefit of final consumer n for offering flexibility [€]
$BRPdowndr_t$	BRP need for downward demand response at time t [MWh]
$BRPupdr_t$	BRP need for upward demand response at time t [MWh]
CC	cost of RES curtailment [€\MWh]
C_{exp}	cost of distribution grid expansion [€ \MW]
C_{flex}	cost of flexibility for the DSO [€\MWh]
C_{inv}	cost of investment in grid expansion [€\MW]
$COSTBRPDWN_{t,f}$	reservation cost of BRP f at time t for downward demand response [€\MWh]
$COSTBRPDWN_{t,f}$	reservation cost of BRP f at time t for downward demand response [€\MWh]
$COSTBRPUP_{t,f}$	reservation cost of BRP f at time t for upward demand response [€\MWh]
$COSTBRPUP_{t,f}$	reservation cost of BRP f at time t for upward demand response [€\MWh]
$COSTDSO$	reservation cost of the DSO for flexibility purchasing [€\MWh]

$curtpv_{t,f}$	curtailment of excess PV energy at time t owned by BRP f[MWh]
$curtw_{t,f}$	curtailment of excess wind energy at time t from BRP f[MWh]
$D1_{t,f}$	input demand per BRP f in time period t
$DAPV_t$	Day-ahead PV generation forecast for time t [MWh]
DAW_t	Day-ahead wind generation forecast for time t [MWh]
ΔRES	change in renewable energy profile [MWh]
$down_{ag,t,f}$	downward demand response per aggregator ag at time t for load of f [MWh]
$DSOdown_t$	DSO need for downward flexibility at time t [MWh]
$DSOup_t$	DSO need for upward flexibility at time t [MW]
$dup_{ag,t,f}$	upward demand response per aggregator ag in hour t for load of f [MWh]
exp	total grid expansion needed to relieve congestion [MW]
f	Balance Responsible Party f
$flexdown_t$	downward flexibility offered by final consumer in time t [MWh]
$flexup_t$	upward flexibility offered by final consumer in time t [MWh]
G	transfer payment cost for aggregator for providing downward demand response [€\MWh]
$g_{t,f}$	energy produced per generator f at time t [MWh]
$INVCOST$	annualized grid investment cost [€\MW]
λ_t	day-ahead market price per time period t [€\MWh]
MC_f	marginal costs per generator f [€\MWh]
MKT_f	wholesale market profits of the BRP f
$MKTeff$	market effect of demand response for the BRP [€]
MP_{ph}	marginal price at peak hour [€\MWh]

MP_{oph}	marginal price at off-peak hour [€\MWh]
$PMAX_f$	input maximum power per generator f [MWh]
$PMAXag$	limits for demand response per aggregator *ag* [MWh]
$PMIN_f$	input minimum power per generator f [MWh]
POP_t	peak\ off peak tariff faced by consumer at time period t [€\MWh]
$Profit_{ag}$	Aggregator profits [€]
ps_t	DSO power at slack node during time *t* [MW]
ps_t	power at the DSO slack node at time t [MW]
$pur_{t,f}$	purchases per BRP *f* in time period *t* [MWh]
$PVfda_{t,f}$	input PV generation in hour t per BRP f [MWh]
$qadjdown_t$	aggregator's need for downward demand adjustment at time t [MWh]
$qadjup_t$	aggregator's need for upward demand adjustment at time t [MWh]
$qaggdown_t$	total downward demand response offered by aggregated consumers at time t [MWh]
$qaggup_t$	total upward demand response offered by aggregated consumers at time t [MWh]
$qbrpdown_{t,f}$	downward flexibility won by BRP *f* at time *t* [MWh]
$qbrpup_{t,f}$	upward flexibility won by BRP *f* at time *t* [MWh]
$qdsodown_t$	downward flexibility won by DSO at time *t* [MWh]
$qdsoup_t$	upward flexibility won by DSO at time *t* [MWh]
$RealPV_t$	Real time PV generation for time t [MWh]
$RealW_t$	Real time wind generation for time t [MWh]
RET_f	retail profits of BRP *f*
$RETC_f$	retail price paid by consumers of BRP *f* [€\MWh]
$RETeff$	retail effect of demand response for the BRP [€]

$sales_{t,f}$	sales per BRP f in time period t [MWh]
SC_f	input start up costs per generation f [€]
$scosts_{t,f}$	start up costs decision variable per generator f [€]
t	time period [h]
$t24$	24 hour subset of t
T_{oph}	off-peak tariff that the consumer affected by demand response faces [€\MWh]
T_{ph}	peak tariff that the consumer affected by demand response faces [€\MWh]
$trafolim$	power limit of transformer [MW]
$u_{ag,t}$	binary decision variable for upward demand response per aggregator ag at time t
$v_{ag,t}$	binary decision variable for downward demand response per aggregator ag at time t
$WIND_{t,f}$	input wind generation in hour t per BRP f [MWh]
$z_{t,f}$	binary decision variable in time t for unit f

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Chapter 1

Introduction

1.1 Smart Grid Context: Changing Electricity Production and Consumption

The electricity industry is undergoing policy and technology driven changes. From a policy point of view generation of electricity is moving towards a more renewable and sustainable system. Installed capacity of renewable generation sources (RES) has expanded significantly in Europe over the past 20 years. Figure 1.1 shows the growth in installed generation capacity for the EU28 countries from 1990 to 2014 [1]. A steep growth in variable renewable generation such as wind and solar energy can be observed during the last decade. It is expected that RES will continue to grow during the next decades. According to the European Commission the share of renewable electricity generation in Europe will grow from 25% today to 50% in 2030 [2].

Technology driven changes refer, among others, to users that have access to in-home energy systems that can generate and store energy, and manage their consumption profiles. New technology enables a shift towards the 'smart grid', defined as any combination of enabling technologies, hardware, software, or practices that collectively make the delivery infrastructure of the grid more versatile, secure, accomodating, resilient and ultimately useful to consumers [3].

Smart grids allow users to actively make decisions upon their electricity consumption based on prices. Users now have access to new technologies such as solar panels, batteries, heat storage and smart metering devices. The consumer is becoming an active decision agent instead of a price-taker.

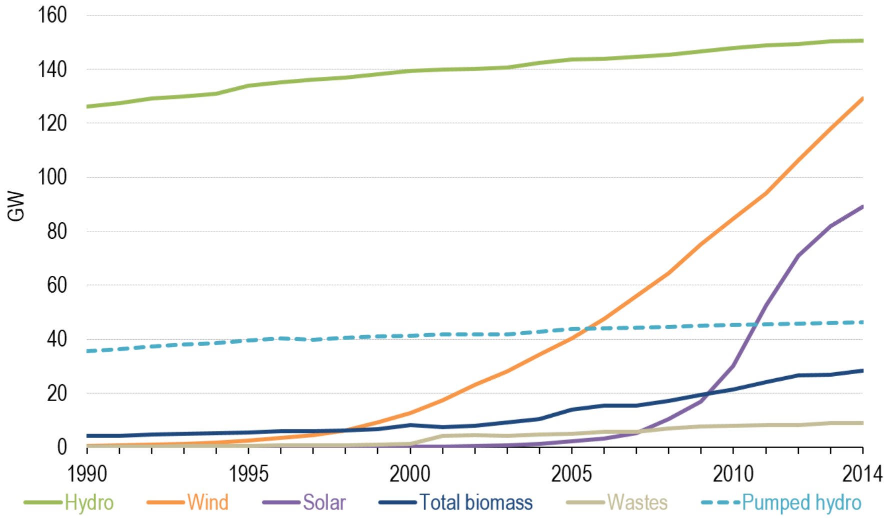

fig. 1.1. Electricity generation capacity, EU28, 1990-2014.

However, the current electricity market structures were not designed with this shift in mind. Traditionally in power systems load was taken as a given and generation had to adjust to keep system balance. Current structures focus on a market where generation follows the needs set by demand. In a smart grid environment new market arrangements are needed to take advantage of the new available technologies both on the consumption and on the generation arenas. In this new environment available generation drives the behavior of demand.

Flexibility contracting is a potential solution to manage this shift. Flexibility is defined as the modification of generation injection and/or consumption patterns in reaction to an external signal (price signal or activation) in order to provide a service within the system [4]. An actor who can offer flexibility to the grid or the market is called Flexibility Service Provider (FSP). Flexible resources may be contracted by several parties such as Balancing Responsible Parties (BRPs), DSOs , TSOs, and aggregators [4].

FSPs need to be aggregated in order to reach a critical mass that can participate in the wholesale market. Due to the scale of the power system a response from many consumers at the same time is needed in order to make a difference. The average consumption of a household is between 4-10 kWh, and can only offer a small portion of that as flexibility; while renewable energy generation is in the order of magnitude of thousands of MWh. Consumers need to be aggregated to be able to respond to system needs. Aggregation is also useful given that consumers might not have the necessary knowledge or interest in market trading to make the best decisions. The need for an intermediary between consumers and the markets becomes apparent.

The independent aggregator is a new role that arises as an intermediary between the end-consumers, generators, the system operators, and the other existing market participants. Aggregation is a commercial function of pooling consumption changes (but also e.g. distributed generation changes) from customers to provide energy, flexibility, capacity and services to other actors in the system [5]. The aggregator's function is to pool and manage the flexibility of small consumers to reach a critical mass so that their participation can be significant enough for the market and useful for the system. The interactions of the aggregator with current market participants are source of debate.

The introduction of the aggregator as a new market participant poses challenges to the existing market design. The main issue being that the aggregator offers flexibility based on demand response contracts with consumers that already have retail contracts with another party. For the rest of this thesis it is assumed that the BRP acts as retailer. The BRP must procure enough energy to meet the needs of the consumers in its portfolio. It will do so by participating in the long and short term markets for electricity supply. A BRP is defined as a trader on the power exchange market on behalf of members of its portfolio [6]. BRPs are market parties responsible of ensuring that energy supply and load match during a given time period: if the balance is not maintained, the BRP is required to pay imbalance costs [7].

Market design enables actors to trade flexibility among themselves. The way in which markets are designed defines which actors have access to flexibility resources at specific times and places. Market design changes are necessary to allow flexibility service providers access to markets that value the resources being offered. The importance of market design is highlighted by the European Commission (EC): *'market design is the set of arrangements which govern how market actors generate, trade, supply and consume electricity and use the electricity infrastructure. It is important that these arrangements, or in other words the design, can transform the energy system and enable network operators, generators and consumers - both households and industry- to take full advantage of new technology. The wholesale and retail markets should provide the basis for investment decisions, and boost the development of new services by innovative companies [2].'*

1.2 Thesis Motivation: Challenges to Integrate Demand Response into Electricity Markets

The integration of demand response into electricity markets has consequences for current commercial transactions and grid operation on two levels:

- System wide impacts: affect the entire balance of the grid at the transmission level. On a commercial level the effect of system wide impacts is dealt with by the wholesale market.
- Local impacts: relate to effects on distribution grid management. Renewable energy has an impact on grid management due to non-controllable variability, partial unpredictability and locational dependency characteristics [8].

1.3 System Impact of New Technologies

System wide impacts of new technologies are given by changes on both sides of the market. Supply sees the integration of variable generation and demand sees evolving load patterns given by the introduction of batteries, smart home systems, and in the future electric-vehicles.

At a system-wide level balance must be kept at all times. In electrical power systems total production must instantaneously and continuously match total load. When this equality is maintained the system is said to be in balance and the frequency (of 50 or 60 Hz) is maintained. Balancing becomes a challenge due to new technology introduced in both generation and load.

1.3.1 Variable Generation

The system's reserves must be able to cover variability in renewable energy generation. The variability of RES generation adds complexity to network balancing [9]:

- Uncertainties in forecasting lead to plant scheduling challenges.
- Variability of resources leads to possible large and hard to predict fluctuations in power output that require special countermeasures.

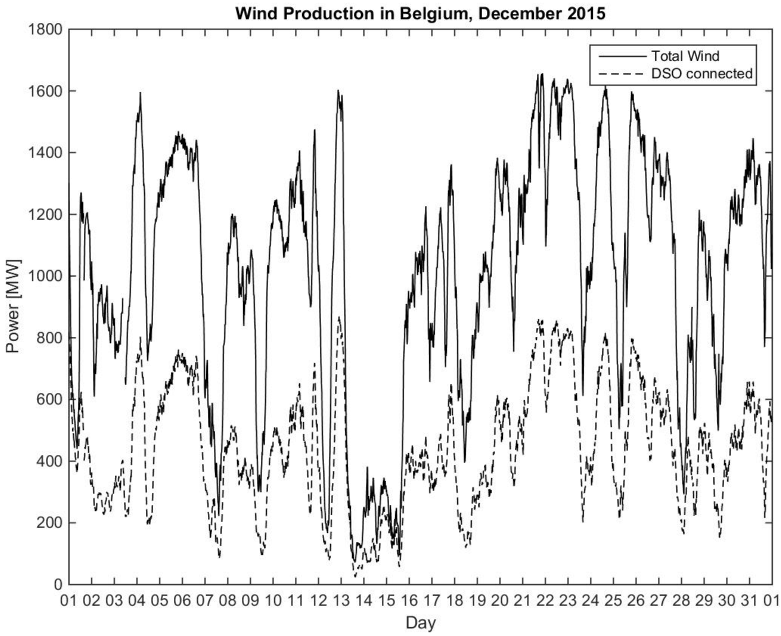

fig. 1.2. Wind generation in Belgium, December 2015.

Wind power generation is characterized by possible fast peaks and drops in generation. The system operator must have adequate reserve capacity to deal with fast acting changes even when they are accurately predicted in order to maintain system balance. Figure 1.2 exemplifies the expected and measured wind generation pattern in Belgium during December 2015. A large part of the wind generation is connected to the distribution grid, this means that variability must be managed on a local level when congestion could occur. In Belgium, over 50% of RES installations are connected to the distribution grid [10]. In addition, large fluctuations in wind power can be caused by sudden storm disconnections [9].

Solar power generation presents a characteristic pattern that goes from zero in the early morning, reaches a peak throughout the day depending on irradiation patterns, and decreasing to zero again at night. Solar energy is also subject to seasonal variability, meaning that firm power output might vary significantly throughout the year.

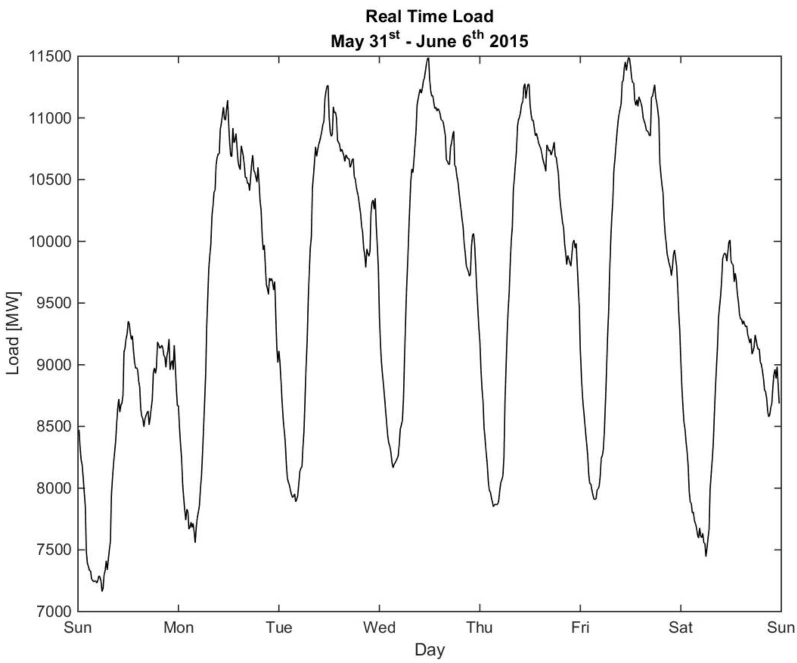

fig. 1.3. Real time load for a week in Belgium, May 2015.

1.3.2 Evolving Load Patterns

Load patterns are given by user behavior and dependent on system characteristics and seasonal needs. Grid users present different power needs throughout the day depending on their activity. Weekdays differ from weekends and holidays. Seasonal effects can also be observed, for example when electricity is the main source of heating in households load will be higher in winter. Figure 1.3 represents a typical load pattern throughout a week in Belgium in May 2015. Consumption tends to be low at night, rising throughout the day and peaking at around 18h to 21h.

Load patterns are expected to change with the introduction of new technologies such as electric vehicles (EVs), heat pumps, and end-user storage capabilities. EVs will make an important contribution towards the decarbonization agenda in Europe [11]. In the future, it will be necessary to accommodate demand growth for EV charging in the distribution grid. EV charging represents a challenge for the grid if all users decide to charge their vehicles at the same time, presumably in the evening as soon as they arrive home from work. This could potentially overload the grid and increase the necessary peaking power and grid capacity significantly. Adding peaking generators and reinforcing the grid might not be an efficient solution, given that a big part of the capacity is idle during many hours throughout the day.

1.3.3 Commercial Solutions

As stated earlier demand response flexibility is needed to deal with the integration of renewable energy. Given the right signals, demand can accommodate the variability of renewable generation. Stakeholder interactions dictate how actors in the market communicate, trade, activate services, and settle their positions. On the one hand, DSOs and TSOs are regulated parties subject to remuneration schemes based on quality of service provision and efficiency. On the other hand, providers of flexibility are private actors motivated to participate in the market if it is in their best interest. The decision making process on each side is different. Different actors want access to the same flexibility resources for different purposes. The coordination of the provision of services depends on the market design in place, and the mechanisms that allow the parties to engage in trade.

The buyers of the DR as a commodity could be commercial actors, or system operators. Commercial actors seek to buy energy at a lower price, they include retailers who need to fulfill load commitments, or renewable energy generators who need to cover variations in their forecasting. Procurement procedures for commercial parties and for system operators - regulated parties- are different in nature. Commercial parties participate in the long and short term competitive electricity markets. System operators are regulated parties who tender for reserves on a long to mid-term basis.

System wide challenges relate to the appropriate balancing of differences that arise between long term commitments and short term resource availability. In the short term, system operation comes into play and system boundaries need to be respected. A contracting framework that enables the use of flexibility without endangering system reliability is needed. If the short term price adequately reflects the needs of the system it will provide the necessary signals for long term investment. Therefore, this thesis focuses on examining the short term wholesale market design enabling the use of flexibility.

1.4 Local Impact of New Technologies

On a local level distributed energy resources (DER) consist of small-to-medium scale resources connected mainly to the lower voltage levels (distribution grids) of the system or near end users. These include distributed generation, energy storage, and demand response capabilities [12]. The introduction of RES has contributed to the growth of Distributed Generation (DG) as users install solar panels in their homes, and other other units, such as CHP (combined heat and power) are installed in the distribution grids. DG are all installations connected to distribution systems or on the consumer side of the meter [13]. Distributed generation is growing because RES and Combined Heat and Power units are suitable for medium and small-scale installations. The European Commission proposes that DG should be taken into account when planning network expansions [14]. These technologies, coupled with the introduction of EVs and storage systems are causing in the topology of the distribution network.

Distribution system operators (DSOs) are now faced with a number of issues regarding the impact of distributed generation: voltage deviations, increased losses, protection sensitivity, system balance and reserve, network robustness and power quality [15], [16]. Congestion issues in distribution arise when transformers and cables are overloaded. In areas with low demand, electricity generation from RES may exceed local consumption, and distribution systems have to be reinforced and extended [17]. In addition, generation connected to the distribution grid might cause backflows, energy flowing from the distribution system to the upstream transmission system [18]. This impacts the distribution network capacity and congestion given that overload of feeders may take place due to high generation during low consumption periods [19]. Distribution networks were not originally designed to accommodate generation [20]. Distribution grids were built with a 'fit and forget' approach to be able to deal with the expected peak loads. Applying this approach to distributed renewable energy sources (DRES) connections in the distribution grid will cause the need for incremental reinforcement of the network [21]. These grid expansions would probably only be used during a limited number of hours per year, making them an expensive and inefficient solution.

Technical solutions to the technical challenges include investment in new lines, power electronics, advanced protection schemes, system reconfiguration and storage [18]. Another way to deal with these issues is through market based solutions that seek to adapt user behavior to generation and network conditions. An active Distribution system operator would be able to monitor the grid and adjust technical settings to optimize operation. Distribution grids of the future will implement a mix of technical and market based solutions. The analysis of technical solutions is out of the scope of this work. This thesis deals with market based solutions to manage congestion, taking the grid as a constraint.

In a local context the commercial challenge relates to appropriate incentives for investment in active distribution systems. Investment is needed on both sides of the market. Investment needs to be carried out by the system operators impacted and by the users installing DERs or providing demand response flexibility. DSOs have to invest either in grid expansion or in grid management systems. Consumers can decide to invest in solar panels, batteries, smart home systems, and ICT to enable demand response. The trade-off in the cost of contracting flexibility or building new lines represents the cap-price at which it is feasible for a system operator to buy flexibility. Investments are carried out if each stakeholder estimates that costs can be recovered through either savings or direct remuneration. Long term contracting enables investment by ensuring income for the involved stakeholders.

1.5 Research Objective: Market Coordination Mechanisms

This thesis studies the integration of demand response as a solution to the challenges presented above. The challenges posed by the evolving power sector are observed on both a system and a local level. Therefore, the integration of demand response into electricity markets is analyzed on a system wide level through wholesale market integration, and on a local level through the proposition of possible local flexibility market designs.

It can be said that the integration of demand response needs to be coordinated on two levels of procurement:

- Wholesale market: user participation in the wholesale market is enabled by aggregated demand response possibilities. If users have visibility of market conditions they have a chance to decide whether they want to consume electricity at a certain hour and price. User response can be thought of as a tradeable commodity since it contributes to system balancing. The introduction of a third party aggregator acting on a load portfolio owned by a BRP causes ambiguity over the balancing responsibility of both the aggregator and the existing BRP. For example, the BRP has esteemed that one of its consumers needs 100 kWh at a certain hour. The aggregator has an agreement with that same consumer to reduce its consumption to 80 kWh during that same period of time. If the BRP is unaware of the actions of the aggregator it will be imbalanced by +20 kWh due to actions out of its control.

- Local market: System operators can also make use of demand response services. Traditionally only the TSO has engaged in reserves contracting, while the DSO has kept a more passive role. Now, distributed energy resources cause a need for the DSO to also use reserves.

In order to study these two procurement needs this thesis provides answers to the following research question and sub-questions:

- On a wholesale level:
  - How is aggregated demand response integrated into the wholesale market?
  - What is the effect of the participation of aggregated demand response in the wholesale market?
  - How are the costs and benefits of demand response in the wholesale market allocated among market participants?
- On a local level:
  - Why is a local market necessary?
  - How can a local market for flexibility be organized?
  - What is the local need for flexibility and what is its value?
  - How can a DSO-led reserves market for flexibility be organized?
  - If the DSO competes for flexibility with the BRP who is better off?

1.6 Thesis Outline

To answer the research questions proposed above, the thesis is set up in two parts. Part I of the thesis focuses on the integration of flexibility into the wholesale market. The main challenges and proposed solutions for wholesale demand response integration are discussed and modelled empirically. Part II focuses on local flexibility contracting. The conditions that lead to local demand for flexibility are discussed and quantified. Two possible local market design approaches are concluded and modelled: a local market for reserves, and local competition for flexibility.

Part I

Chapter 2 sets demand response within wholesale market design. Key aspects of electricity market design form the basis for the analysis. Demand response is placed inside a conceptual design framework. Demand response remuneration is highlighted. The question of whether demand response should be remunerated in same terms as other resources is posed. Proposals in literature and market implementations are discussed.

Chapter 3 analyzes the specific effects of demand response aggregation in the wholesale market and specifically in the BRP's portfolio. The rebound, when consumers resume their load patterns after a demand response event, is defined. Two effects of demand response are analyzed: a market, and a retail effect. The attribution of the imbalance caused by demand response is discussed. Adjustment mechanisms to deal with these effects are proposed.

Chapter 4 proposes an empirical analysis of the effects of demand response introduced in chapter 3. A decision making model is introduced to exemplify the ideal outcome of the market taking into account an independent aggregator and BRP's who own both load and generation portfolios.

Part II

Chapter 5 explores the first available concepts of local grid management through microgrids and virtual power plants (VPP). The concept of flexibility and locality are introduced. The evolution of concepts towards the need for a local market to handle DER growth is outlined. A definition of a local market for flexibility is proposed. Current local market design proposals are described to arrive at main characteristics that form local market design. The chapter concludes on two main variants of local flexibility contracting: flexibility as a reserve and local competition for flexibility.

Chapter 6 studies the contracting of local flexibility in a reserves-type market. The DSO's demand for flexibility is quantified based on an analysis of network congestion. The value of flexibility is given by the alternative cost of reinforcing the network in order to solve the foreseen congestion. A decision model where the DSO either buys flexibility or invests in grid reinforcements is proposed.

Chapter 7 studies the case of local competition for flexibility. A BRP and a profit maximizing aggregator are introduced. The BRP's need for local flexibility is found to come from variations in RES profiles at times when there is congestion in the network. The valuation of the BRP's flexibility is given by the cost of the imbalance caused by the variations in RES profiles. A decision making model where a profit maximizing aggregator decides who to allocate flexibility to is proposed.

Chapter 8 summarizes the conclusions of this PhD dissertation. Key contributions are outlined and future research possibilities are described.

Part I

Chapter 2

Demand Response in the Wholesale Market

Traditionally electricity consumers have been passive participants in the commodity markets. It has been assumed that all load must be supplied at all times, and it does not vary too much with respect to prices. One of the main reasons for this is that consumers are not generally aware of electricity market conditions. They have little or no visibility on the price of the electricity that they are consuming at a certain hour. Final consumers negotiate their electricity consumption through a retailer, who then represents them in the wholesale market. The tariffs that consumers pay to the retailer might not be reflective of the prices in the wholesale market. It is up to the retailer to offer deals that reap a profit margin with respect to the wholesale market prices.

The introduction of smart meters and communication technologies open the door for consumers to take a more active role in the electricity market. If consumers are exposed to real-time price signals, they can make decisions to change their behavior and modify their load patterns. The system is at a need for this type of response due to the growth of renewable energy. Therefore the system is on the verge of experiencing a shift of paradigm from the traditional view where supply is adapted to the needs of demand to a new market where demand responds to the available supply. Figure 2.1 depicts how load patterns can adapt to exploit renewable energy availability. Demand response is defined as the changes in electricity usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time [22].

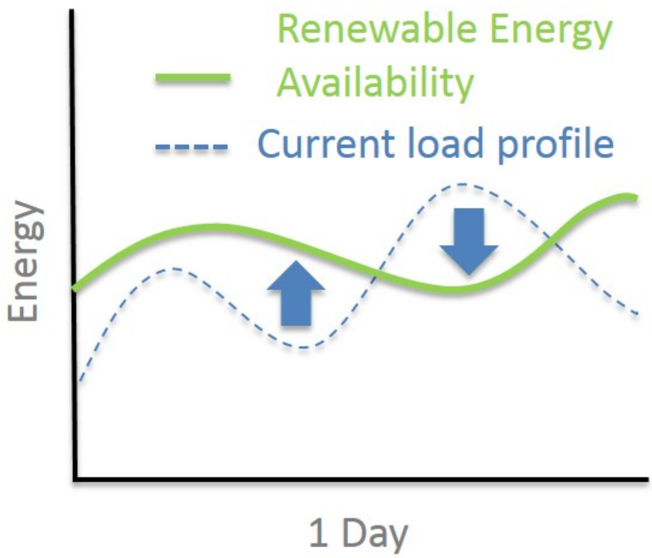

fig. 2.1. Responsive load can adapt to renewable energy availability

In order to promote the best use of renewable energy, electricity market design needs to create the appropriate signals for consumers to respond to. When there is a high amount of renewable energy available the market price should be low to promote consumption, and when there is a low amount of renewable energy prices should be high. As consumers respond to these price signals the full potential of renewable energy can be exploited. This chapter focuses on short-term contracting of demand response by commercial actors. Specifically, the integration of demand response into the day ahead wholesale market is studied.

In order to place demand response within electricity market design, a definition of flexibility and demand response is given in section 2.1. Then, key dimensions of electricity market design are analyzed in section 2.2. Demand response is placed within the possible contracting frameworks for electricity trade in section 2.3. Third, demand response remuneration at either the full marginal price or the marginal price minus a deduction is discussed in section 2.4. Finally, chapter conclusions are presented in section 2.5.

2.1 Definition of Flexibility and Demand Response

Flexibility is defined in chapter 1 as the modification of generation injection and/or consumption patterns in reaction to an external signal (price signal or activation) in order to provide a service to the system [4].

System flexibility is defined as the ability of a power system to cope with variability and uncertainty in both generation and demand, while mainatining a satisfactory level of reliability at a reasonable cost, over different time horizons [23]. From a broad system perspective flexibility is defined as the ability of a power system to maintain continuous service in the face of rapid and large swings in supply and demand [24]. In [25] flexibility is defined as the ability of a system to deploy its resources to respond to changes in net load, where net load is defined as the remaining system load not served by variable generation. Flexibility can come from a variety of sources, such as electricity storage, flexible supply, flexible demand and inter-regional capacity [26].

In a historical view the flexibility of power markets is characterized by their ability to efficiently cover fluctuating demand [27]. As RES grows this definition of flexibility needs to be revised, there is a need for demand to adapt to generation availability. Parties capable of offering flexibility, such as aggregators, generators, consumers, BRPs involved, are called Flexibility Service Providers (FSP). In this thesis flexibility coming from demand response is studied in detail. Flexibility coming from generation resources is out of the scope of the analysis.

Demand response is defined as modifications of electricity consumption in response to price and the implementation of more energy efficient technologies [28]. In another proposed definition DR encompasses a series of automated or manual actions taken by final consumers aimed at intentionally changing their electricity consumption profile in response to signals that are in line with the market or network conditions [29].

In a definition by the U.S. Department of Energy demand response refers to changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized [30].

The wider implementation of demand response should arise from coordinated actions of the involved stakeholders along the electricity supply chain [28]. Dynamic pricing and demand bidding, are usually adopted by large consumers but responsive technologies can also enhance the responsiveness of small and medium retail consumers [31]. It was recognized that when demand is unresponsive to prices, generators are tempted to manipulate the market towards high prices [32]. Therefore it is important to implement initiatives that empower consumers to respond to market conditions.

2.2 Key Aspects of Electricity Market Design

In order to integrate demand response and RES into existing markets it is necessary to take a look at the key aspects of electricity market design. During the de-regulation of electricity markets several variants of market design were proposed. The main differentiating factors are those concerning temporal, price clearing, spatial, and contractual dimensions of trade.

2.2.1 Temporal

The temporal dimension refers to the moment when electricity is contracted for a specific delivery time period. Three distinctions are studied below:

- Long-term markets.
- Short-term markets.
- Real-time markets.

Long-Term Markets

In the long-term, buyers and sellers contract electricity several months or years before delivery date. In a forward market two parties agree on a price, a quantity and a future date for delivery. The negotiation process for a forward contract can be lengthy and involve substantial transaction costs. In order to facilitate long-term transactions standardized forward contracts, called futures contracts, can be drafted. In a market for futures contracts, participants can buy or sell physical or financial products, called derivatives, for delivery on a specified future date at today's prices [33]. These contracts allow buyers and sellers to contract prices and quantities over a period of time in order to hedge risk [34]. Futures can also be traded by speculators that will not necessarily do the physical delivery of the commodity [35].

Long-term contracts are traditionally negotiated as either a fixed price contract where the price per MWh is known in advance, as an indexed price contract where the price is indexed to either inflation or the cost of another commodity (such as fuel prices or electricity spot prices), or as a tolling contract which provides the buyer the right to use the seller's facility to convert fuel into electricity [36]. Traded products in long-term contracts can be base, peak, seasonal and annual.

In view of intermittent resources and distributed generation there is a need to take into account variability of the output profile at all time frames. From a long-term perspective, a large share of renewable energy complicates real-time system operation since availability of these resources is uncertain. Long-term contracts become more important as a hedge to increasing variations in spot prices. However, long-term contract risk is increasing since their price is negotiated based on the expected short-term price close to actual delivery, which is becoming harder to predict. The predicted contract price used for the long-term contracts has a high chance of being different from the short-term electricity price.

Due to predictability issues, wind and solar power generators have more difficulties stepping into long term electricity contracts. If they sign such contracts they are more exposed to spot price variations than conventional generation units. In case they produce less than contracted, they will have to buy the missing electricity on the short-term market to cover their short positions. During those moments, they are expected to face prices higher than the long term contract prices as they are typically set by the marginal generation cost of peaking units.

Short-Term Markets

The short-term electricity markets, also referred to as spot markets, are the day-ahead and intraday markets. The day-ahead market is either an exchange or a pool and is operated as an auction [37]. As in the long-term markets, the short-term can include financial transactions in the form of commitments to sell or buy without the backing of physical assets. The only truly physical market is the real-time market where short or long positions must be settled [37]. The markets closer to real time become more important due to variability of RES. The amount traded in these markets is related to errors in prediction patterns of RES and expected load.

Real-Time Market

Real-time electricity markets (RTM) are defined as the non-discriminatory transaction platforms for providing necessary balancing services, where the market clearing is very close to real time operations of power systems [38].

RTMs can be operated independently by a market exchange or by a system operator for use in system balancing. It is to be noted that system operators are regulated parties and have to follow specific procedures to enter into contracts with service providers.

Real-time markets can also be used to solve transmission constraints that prevent the market outcome from taking place [39]. Close to real time, bids providing regulation volume are contracted and activated by the TSO to cover imbalances on the transmission grid level. The balancing markets cover variations in electricity needs not previously contracted in the day ahead or intraday markets. Suppliers who are short of their predicted position need to buy the missing energy from other suppliers who have long positions, and the same idea applies to buyers with respect to their submitted consumption schedules. This is necessary when the transactions on the forward markets have been financially binding for all resources, including RES. It forces participants to try to submit accurate bid schedules. As the real availability of resources, especially RES, becomes less predictable the balancing market is expected to gain importance.

2.2.2 Market Clearing: Price Formation

The clearing dimension refers to the price setting mechanisms used by each market. Centralized markets accept supply and demand bids and clear the market at the intersection of both curves using an auction mechanism. A merit order of generation units is created, starting with the cheapest available unit up to more expensive units until the entire load amount is covered [40]. The price at which electricity is traded can be determined in different ways, there can be a single price for a market or several prices depending on the type of mechanism selected. Two main approaches have been identified, pay-as-bid pricing and pay-as-cleared pricing.

- Pay-as-bid: units submit a price-quantity bid and are paid at their nominated price for the quantity cleared in the market [41]. This means that each generating unit receives a different payment and there is not a single price for electricity. This type of pricing is more commonly applied to reserves, or ancillary, markets than to wholesale day-ahead markets.
- Pay-as-cleared or Marginal price: all units are remunerated at the marginal price of the system given by the intersection of the supply and demand bids. The price is given by the most expensive generator that has to be dispatched in order to clear the market. In a single clearing area the entire system is cleared at once based on economic principles without taking into

account the physical network. Congestion and losses are then accounted for and the costs for these are levied equally to all system users [42].

Taking into account the spatial dimension of markets during the clearing process results in three particular approaches described below: nodal, zonal and uniform pricing markets.

2.2.3 Spatial

The spatial dimension refers to the geographical area for which electricity is contracted and prices are settled. Depending on the market design this dimension may, or may not, be constrained by the transmission system. In transmission constrained trading, users typically need to contract the necessary transmission capacity for their transactions in advance under an explicit transmission rights auction. In an implicit method, the network is taken into consideration at the same time that bids and offers are matched and the resulting schedule is already network compatible. In contrast, in a copper-plate approach to market design, the market is defined solely by the offers and bids submitted by users independently of their location within the market area and the network assets needed to deliver that electricity. After the market has been cleared the TSO performs load flow calculations to ensure that the schedule is feasible. In case of congestion, units are re-dispatched and usually paid at either the marginal cost or a previously agreed price of operation. Currently, in most markets only the transmission system is taken into account. Distribution has been assumed to be a copper plate connected to nodes of the transmission system.

Depending on the geographic locations taken into account during the market clearing markets can be classified in three categories [38]:

- Nodal Pricing Markets: the object of nodal pricing is to adjust energy prices in a pool to reflect their locational value [43]. The concept of nodal pricing was first proposed by [44] [45] and [46].
- Zonal Pricing Markets: the market is divided into a number of zones that aggregate locations expected to have little or no transmission congestion or constraints zones internally [47].
- Uniform marginal pricing: the market is defined solely by the offers and bids submitted by users independently of their location within the market area and the network assets needed to deliver that electricity. This approach allows electricity to be injected and withdrawn at any location without capacity restrictions [48]. In case of congestion, units are

re-dispatched by the TSO. To do so markets use bid- based, merit-order systems for choosing capacity for countertrade [49].

2.2.4 Contractual

The contractual dimension of trading refers to the way in which buyers and sellers come into contact and agree on trade. There are three main approaches: bilateral, in an exchange, and in a pool.

- Pool market: a mandatory trading platform organized by a market operator where both suppliers and consumers must bid for electricity. Demand and supply offers are matched by a centralized platform and complex bids are accepted. Complex bids are those where generating unit specifications and grid network conditions can be taken into account by an optimization algorithm [37]. A pool facilitates central control, but limits the market participation only to parties who own generation assets.
- Power Exchange: similar to a pool market but participants can choose to participate or not, it is not mandatory. Bids typically consist of basic price-volume block products and exclude complex system and generator characteristics, such as minimum on and off times, and ramping rates [50]. Although some exchanges can also include technical characteristics. An exchange, less technically specific than a pool, encourages parties to form their own generation schedules based on financial positions. This enables traders who do not own assets to speculate in the market while adding liquidity and encouraging competition.
- Bilateral or Over-the-Counter market: buyers and sellers contact each other directly and agree on a price and terms of purchase and delivery of electricity. Participants enter into contracts without involvement, interference or facilitation from a third party [35]. A bilateral market allows participants to make commercial arrangements with physical delivery or with purely financial purposes [51]. As is the case of long-term reserve contracts between market participants and the system operator. These comprise up to 85% of the electricity trade in Europe, and thus are the main trading means for electricity transactions [52]. These markets are adequate for providing the bulk power supply, but real time adjustments are always necessary when injections or off-takes deviate from contracted volumes. Bilateral transactions remain adequate for long and short-term markets, but the outcome of those trading platforms could be too slow for real time transactions. Similarly, information of available resources is important for system operator optimization.

Dimension	Description Wholesale Day-Ahead Market
Temporal	Short-term market where actors trade during the day previous to electricity delivery.
Market clearing	Marginal pricing defined by the most expensive bids cleared.
Spatial	Uniform marginal pricing where the bidding area is assumed to be a copper plate and interconnection capacities are not taken into account.
Contractual	Power exchange where participants submit bids and offers for energy blocks without taking into account specific characteristics of generation assets.

Table 2.1. Description of the wholesale day-ahead market reference scenario

2.2.5 Reference Day-Ahead Wholesale Market Design

This part of the thesis studies the integration of demand response into the day-ahead wholesale market. Drawing upon the analysis above, the day-ahead wholesale market that will be the reference for the rest of this study is described in table 2.1. It is a short-term day ahead market, where bids are paid as cleared and the grid is assumed to be a copper plate. Participants submit hourly bids and offers that are not asset specific.

2.3 Demand Response Integration

Introducing demand response in an effective manner poses challenges for market design. The demand response process must be compatible with the operation of existing markets. This gives way to issues such as the time frame of demand response within the market operation, contracting options, bidding options and pricing schemes. Demand response propositions first started in the 1980s. The term demand side management referred to the planning and implementation of those electric utility activities designed to influence customer uses of electricity in ways that produce desired changes in the utility's load shape [53]. The concept was then expanded to specify that demand side management encompasses load reduction strategies as well as load growth strategies and flexible energy options [54]. At this point, power systems were working as integrated vertical utilities and electricity markets as known today did not exist. Demand side management was seen as a strategy that utilities used to cope with the system's demands at a lower cost.

The de-regulation of markets and the growth of RES energy in the past 15 years has renewed interest in demand response mechanisms. Demand response programs motivate end consumers to change their use of electricity in response to changes in price. Final consumers supply demand response through changes in their consumption patterns, use of distributed generation or storage capabilities. Reaping the potential of demand response means providing mechanisms that allow all consumers to access the existing electricity markets.

The suppliers of demand response can be both household and industrial consumers. Electricity consumers can be classified according to their main activity as industrial consumers, commercial business consumers and household consumers. Each segment presents different capabilities for demand response. For example, energy intensive industrial consumers can switch their production patterns to take advantage of low electricity prices in off peak hours. Similarly, they often own generation sources or heat recycling facilities that enable them to respond to high electricity prices. In contrast, aggregated household consumers can offer flexibility through modulation of appliances such as electric heaters, water boilers, refrigerators, and air conditioners.

DR can be activated pursuing different objectives:

- Congestion relief: during peak hours the system operator can call for downward DR in order to alleviate congestion problems in the grid.
- Renewable energy potential exploitation: DR is used to take advantage of variable renewable energy availability to reap the most out of the installed wind or solar generating capacity as depicted in figure 2.1.
- Avoid use of peaking generating units: DR has been shown to replace expensive peaking generators and decrease overall system costs [55]. These units are no longer needed as much if demand is shifted from high price hours to lower price ones.
- Costs savings: consumers can react to market prices reducing consumption when prices are higher and shifting it to periods when prices are lower in order to reduce their energy bill.

The contracting approach to demand response depends on the desired objective. Different modalities of demand response programs have been developed over the years to fufill different needs. In a survey of demand response initiatives three different types of demand response programs have been identified. The first classifies DR according to the control mechanism which can be centralized or decentralized. The second one classifies it according to the incentives offered to consumers be it explicit or implicit. The third one is DR based on a decision variable - task scheduling or energy management based DR [56].

In the wholesale market demand response is included mainly through explicit mechanisms. The difference between implicit and explicit demand response is outlined in [22]:

- Explicit demand response (also called incentive-based): consumers directly receive incentive payments to respond to system conditions [57]. These incentive instructions are received from the market, the system operator or through an aggregator. It is assumed that under this scheme load is directly controllable and will respond as expected or face a penalty.
- Implicit demand response (also called price-based): consumers receive real-time, or block tariff, price signals and respond according to their priorities [58]. These affect the market indirectly if there is a significant mass of consumers responding to price signals. Price based programs are better suited to fulfill cost saving objectives. They are not immediate or reliable enough to serve as a tool for congestion management or RES utilization.

Given that the focus of this thesis is the integration of demand response into the wholesale market the following analysis will go in depth into explicit demand response programs. Within explicit demand response programs demand bidding programs are proposed, based on the customer's bids that are realized in the wholesale electricity market [59].

2.3.1 Timeline of Contracting and Operation of Demand Response

Electricity market design must allow demand response to participate as a part of the market operation. This means setting up a contracting process that determines the price, the amount, and the form of participation of different DR resources. There are three main stages of demand response contracting as depicted in figure 2.2.

- Ex-ante: this is the contracting stage and the establishment of a baseline consumption profile. The aggregator contracts with the final consumer who provides demand response. They agree on the terms of service including amount of activation, mode of activation, expected activation times and amounts, and price agreements. A baseline is necessary for programs where the consumer is remunerated based on a difference between their forecasted consumption and a real lower (or higher) consumption during certain hours [60]. Once the customer baseline is properly established,

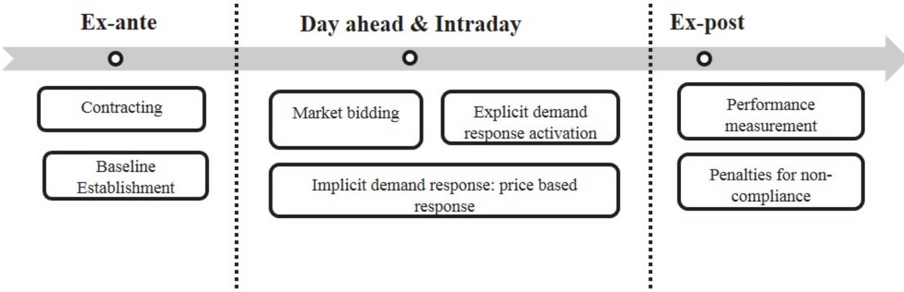

fig. 2.2. Stages of demand response within market operation

demand-response capacity is well defined and can be traded [61]. It is not necessary to establish a baseline for implicit demand response programs, since the benefit for the consumer lies in the savings in energy achieved from modifying their behavior.

- Day-ahead and intraday markets: this is the moment during market operation where demand response is traded and activated. Controllable loads can bid into the market as a commodity, while non-controllable loads respond to price signals.

- Ex-post: verification and measurement of the demand response activation is necessary. This stage is particularly important for load providing DR upon a baseline, there must be a verification procedure to ensure that they complied when an event was called forth. It is especially important for consumers who obtain reduced tariffs over a period of time for being available to curtail on short notice. To avoid claims and billing issues it is important to clarify a compliance methodology during the contracting stage of demand response.

2.3.2 Benefit of Demand Response in the Wholesale Market

Figure 2.3 presents the intersection of supply and demand in the wholesale market. The x-axis presents the quantity of electricity demanded in the wholesale market, while the y-axis presents the price at which it is sold at a certain time period t. Line D1 is a simplification of an inelastic demand curve for electricity, it represents the initial demand before the actions of an aggregator. The step wise supply curve is represented by S. Generation costs increase in steps according to the technologies that are dispatched to cover demand at a certain hour. The cheapest available technologies -usually nuclear, wind and solar generation- are dispatched first, followed by coal, gas, and fuel oil. The market price of

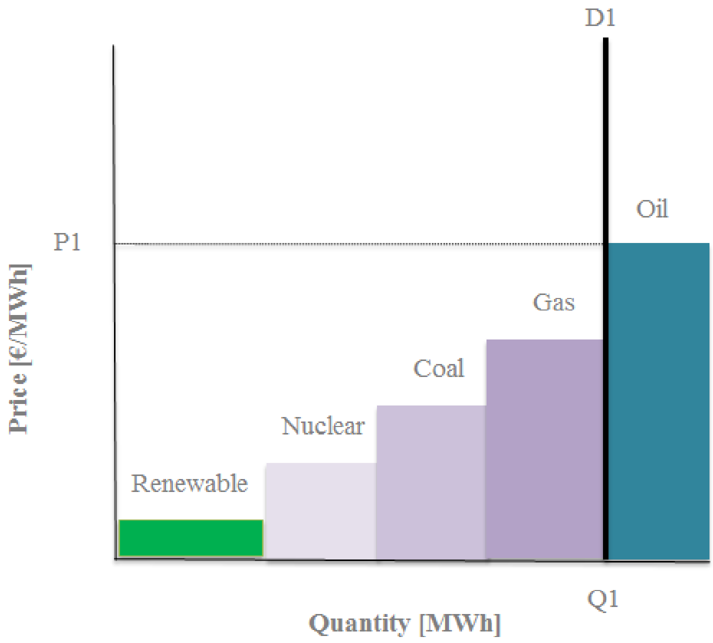

fig. 2.3. Merit order dispatch in wholesale markets.

electricity, P1 in the figure, is formed by the intersection of the demand and supply curves, this is called market matching.

In the wholesale market the matching process is repeated for every time step that the market clears. Thus, in every period the cheapest generation technologies that can supply the load are chosen in the merit order and a price for energy is formed. In marginal price, or pay-as-cleared, markets demand pays the cleared price P1 and all generators receive the same price P1.

In a classical definition, economic surplus is present when a seller makes a sale for a sum greater than the least sum for which he would have been willing to make the sale, or whenever a buyer makes a purchase for a sum smaller than the greatest sum for which he would have been willing to make the purchase [62]. In the wholesale market this means that the net economic benefit of an increase in demand response is the reduction in the total supply-side costs plus demand-side costs of meeting consumers' demand [63].

In figure 2.3 the supplier's surplus is represented by the area above the supply cost curve S, and below the price to consumers P1. The consumer's surplus

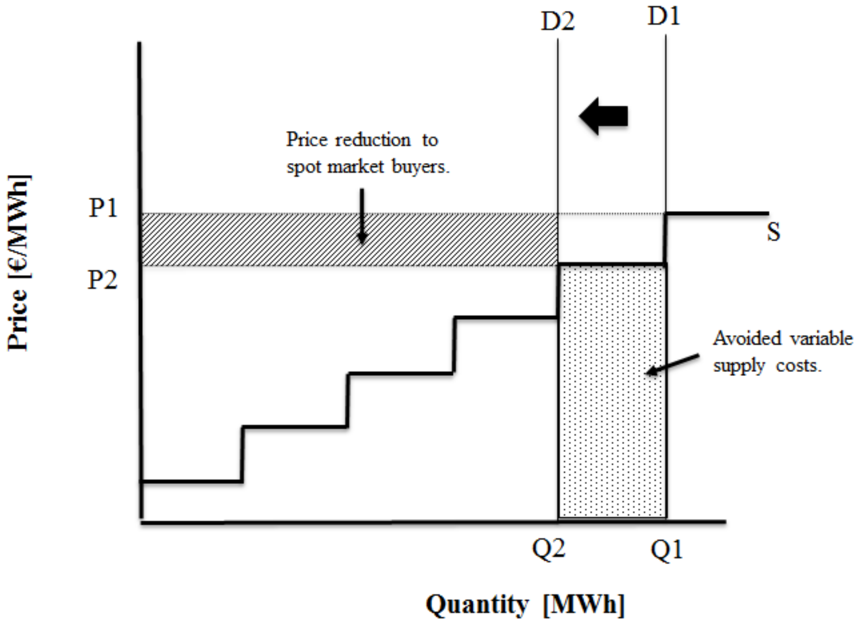

fig. 2.4. Impact of demand response in the wholesale market. Adapted from [65].

is the area above the market price P1. Social surplus is the addition of the consumer's and the supplier's surplus, that is to say, the entire area above the supply cost curve and under D1.

Figure 2.4 presents the impact of demand response in the wholesale market. Demand shifts from Q1 to Q2 in a demand response reduction event. Line D2 represents modified demand after an aggregator makes a demand response offer in the market. A new price, P2, is formed by the intersection of lines D2 and S. A price reduction for consumers is observed, at the same time that generators avoid variable supply costs [64].

It is argued that the price reduction to spot market buyers is a transfer of wealth from generation to load. However, there is a benefit to society as a whole, for generation and load, if the decrease in demand results in avoided supply costs. Expensive units do not need to be used as much, generators avoid the cost, and load pays less for energy.

2.4 Remuneration of Demand Response in Wholesale Markets

Defining an adequate price for demand response integration in wholesale markets has been a matter of debate during several years. The initial programs promoting the integration of demand response into wholesale markets included demand response products traded as capacity (availability), energy during the day-ahead and real-time balancing, and reserves [65].

The Smart Grid task force of the European commision recommends that consumers have a right to sell flexibility in the same terms as other suppliers, the value of a MWh should be decided regardless of who is providing it [66]. The report argues that flexibility resources should receive comparable payment as traditional generation. Furthermore, demand response should be accepted as a flexibility resource in the full range of markets, including capacity, forward, day-ahead, intraday and balancing markets.

However, not everyone agrees that demand response should be remunerated at the same rate as other generators. There are different proposals regarding the adequate remuneration of demand response in the wholesale markets. In the following sections different approaches discussed in prominent wholesale markets are presented.

2.4.1 The LMP - G Debate

It was first proposed that demand response should be remunerated at the locational marginal price (LMP) in United States' federal markets. A review of demand response implementation in the USA shows the initiatives and pilot programs issued to promote demand response participation [67]. In 2008 the Federal Energy Regulatory Commission ruled that demand response should be treated in a comparable way to generation sources and that it could bid into electricity markets [68]. In 2011 FERC ruled, in Order No. 745, that demand response should be remunerated at the full Locational Marginal Price when the dispatch of that demand response resource is cost-effective [69]. It was ruled that demand response should only be dispatched when the incremental payment for it equals the incremental benefit of the reduction in load.

The critics to remunerating demand response at the full locational market price argued that it gave an unfair double payment to the providers of the service [70] [71] [72]. Consumers would earn both an incentive payment for their demand reduction and savings from the energy they didn't consume.

A notion was proposed where consumers should only earn the difference between the locational marginal price and their retail tariff. LMP-G is a proposed method of remunerating demand response where LMP is the locational marginal price of electricity and where G is the retail price per unit the consumer would pay if it were to purchase the units it is willing to forego [71]. The reasoning behind this proposal is that when a consumer does not consume one extra unit of energy he saves the cost of that energy. These savings should be the market based signal needed for consumers to decide whether it is worth it for them to buy electricity or not. However, consumers are not exposed to market prices, it is assumed that they face retail prices that are lower to market prices. The proposal of LMP-G is thought to avoid a double reward for the same service. To illustrate the concept with an example, imagine a consumer who pays 0.10 €\kWh at the same time that the market experiences a price of 0.50 €\kWh. If he were to reduce his consumption at that hour the consumer would save 0.10 €. If this was remunerated at the LMP he would earn 0.10 € plus 0.50 € amounting a total of 0.60 €. Under the proposal of LMP - G the consumer would earn a savings of 0.10 € and be paid an incentive of 0.40 €. This way his total earnings would equal the full LMP, 0.50 €, which is what he would have saved had he been exposed to market prices instead of retail prices.

While the economic reasoning behind the LMP-G proposal is sound, it neglects the costs of demand response intermediation and service provision. Another analysis of the debate proposes that the supporters of 'LMP-G' were wrong to equate the opportunity cost of the customer with the lost value of electricity consumption ignoring other costs and considerations. It is suggested that the optimal price for demand response resources lies somewhere between LMP and LMP-G. And, if there are substantial benefits to demand response, the best solution may be to charge LMP and uplift the cost on a load-proportionate basis [64].

The FERC counter-argued that demand response has a market value equivalent to supply response, and therefore should be remunerated in similar terms as supply at the LMP. In a letter to the FERC, a group of supporters stated that *'since demand response is actually - and not merely metaphorically-equivalent to supply response, economic efficiency requires that it be regarded and rewarded, equivalently, as a resource proferred to system operators, and be treated equivalently to generation in competitive power markets, that is, all resources - energy saved equivalently to energy supplied- should receive the same market-clearing LMP in remuneration [73]'.*

The order was harshly criticized and eventually the ruling was overturned in 2014 [74]. The case was then taken to the supreme court who, in 2016, ruled in favor of Order No. 745 reinstating FERC's initial regulation that demand response should be remunerated at the full LMP.

In order 745, FERC rejected the LMP-G method of determining the per unit payment a provider of demand response should receive. FERC ordered the regional transmission organizations and independend service operators that operate each of the regional transmission grids to design and implement a system of compensation that has the potential to compensate a provider of demand response at LMP. FERC added an important qualification to that requirement, however. A provider of demand response is entitled to receive compensation based on LMP only in circumstances in which payment of compensation based on LMP would satisfy a net benefits test. FERC instructed RTOs and ISOs to identify the hours in which payment of LMP provides net benefits to consumers by determining 'when reductions in LMP from implementing demand response results in a reduction in the total amount consumers pay for resources that is gretar than the money spent acquiring those demand resources at LMP.' The benefit of demand response is seen as the decrease in LMP multiplied by the remaining load [71]. The imbalances brought on by demand response cause costs to the system operator. It was determined that the cost should be allocated to all 'entities that purchase from the relevant energy market in the areas where the demand response reduces the market price for energy at the time when the demand response resource is committed or dispached.'

2.4.2 The NEBEF Mechanism

In 2014 France allowed demand curtailment to bid as energy directly into the wholesale electricity market through the NEBEF mechanism. The first year achieved a modest volume of 313 MWh [57], while more than 3000 MWh of load were curtailed during 2015 [75].

The NEBEF mechanism adopts a modified version of the MP-G approach proposed - and later rejected- in PJM. When a demand reduction is valorized in a market, the aggregator must pay the retailer of the affected load sites. The payment is a price per MWh defined for each 30 minute period. It is applied to the volume of energy corresponding each accepted load reduction program. If the application of the flat rate leads to a negative value, the aggregator pays zero euros to the retailer of the affected load sites. This payment is fiscally equal to a payment for energy delivery.

Demand response reductions bid into the day ahead market and are remunerated at the marginal price minus a seasonal average market price previously defined [76]. The regulated price 'G' varies depending on several factors:

- The price for directly measured or profiled consumers is calculated differently.

Amount Payable	**Off-peak**	**Peak**
Flat rate €\MWh	46.2 €\MWh	
Off-peak, Peak rate €\MWh	38.19	47.29 €\MWh

Table 2.2. Transfer payment value for profiled demand response entities

Amount Payable €\MWh	**Q1**		**Q2**		**Q3**		**Q4**	
	Off-peak	Peak	Off-peak	Peak	Off-peak	Peak	Off-peak	Peak
Rate €\MWh	45.67	64.8	28.49	42.18	28.86	42.25	43.61	60.86

Table 2.3. Transfer payment value for remotely monitored demand response entities

- Peak and off-peak hours are calculated differently for each consumer type.

For remotely measured consumers offering demand reductions the price is calculated as the difference between the reference market price and a value accounting for the price paid by energy sold outside of the market under regulated provisions for the purchase of nuclear energy.

Profiled consumers are those whose load curve is estimated according to regulated load profiles. The price G for demand reduction coming from profiled consumers is calculated based on the fixed flat tariffs that consumers pay for both peak and off-peak consumption.

During 2016 the price paid by the agggregator for demand reduction to the supplier of a final consumer are shown in table 2.2 and were obtained from [77].

2.5 Conclusions

The discussion above illustrates that there are several different valid points of view regarding the remuneration of demand response in wholesale markets. Some argue that demand response should be remunerated at an equal price as other generation resources. Others argue that it should be remunerated at a market price minus the value of the sourced energy. This value, they argue, should be transferred to the supplier of the consumer affected by demand response actions of an aggregator. The definition of transfer payment arises from this discussion, based on the value of 'G' described above:

Transfer payment: the cost of provision of demand reductions representing the value of the sourced energy that the consumers curtailed as a service to the market, in €\MWh.

The exact value of the transfer payment is also a source of debate. It was first argued that it should be equal to 'G', the retail price of the energy sourced. It was later debated that accounting for only the retail price of the energy sourced does not cover all the costs of provision of demand reductions to the market since it is an intermediated service. Costs of aggregation which include telecommunication infrastructure, information management, and contracting are not taken into account in the value 'G' as it was first strictly defined. The aggregation of demand response enables users to participate in the market when otherwise they would have not met the entry criteria. As such, it becomes a service similar to generation.

Summarizing the main positions presented in the discussion flexibility from demand response in the wholesale market can be remunerated at:

- The same price as other generation in the market, namely the marginal price (MP), or
- The marginal market price (MP) minus the retail price of sourcing that energy (MP - G).

Who pays the transfer payment, is also up for debate. When a third party aggregator takes action upon the consumers of a retailer, assumed to be the BRP in this thesis, the retailer suffers an imbalance in it's portfolio. It is assumed that if the retailer then receives the transfer payment from the aggregator the imbalance is compensated. However, most of the discussions so far talk only about demand response reduction only, ignoring a possible rebound effect. It is safe to assume that a consumer who has suffered a demand reduction is likely to consume all or part of that energy at a later hour. An action called the rebound effect. It is worth it to study the full effect of demand response, both reduction and rebound, on the profits of the BRP. In the analysis that follows demand response remuneration is studied at either MP or MP-G taking into account the rebound effect that has until now been neglected in the literature.

Through the 'Avis no. 13-A-25' in December 2013, the competition authority in France recognized a premium to aggregators (demand response operators) per MWh of downward demand response offered each year [78]. The premium is financed by a fee imposed on consumers based on their volume of use. The objective of the premium is to help aggregators reach an acceptable return on investment so that they will be motivated to participate in the market.

Chapter 3

Effects of Aggregation in the Wholesale Market

The introduction of the aggregator as a new market participant poses challenges to the existing market design. The main issue is that the aggregator offers flexibility based on demand response contracts with consumers that already have retail contracts with another party. The BRP must procure enough energy to meet the needs of the consumers in its portfolio. It will do so by participating in the long and short term markets for electricity supply. It is recognized that any load adjustment resulting from a demand response action by an aggregator will result in an imbalance in the retailer's, or balancing responsible party's, position [29]. According to the Smart Grid's taks force there are two impacts when a demand response dispatch occurs in real time and it wasn't initiated by the BRP. The first is that the BRP cannot charge or receive payment for the electricity it sourced on the market. The second one is that the BRP is imbalanced due to the third party aggregation role [66].

Section 3.1 recognizes and defines the rebound phenomenon of demand response. Demand response has two direct effects on the BRP's portfolio, a market effect and a retail effect as explained in 3.2. Proposed mechanisms in literature to deal with these effects are explained in section 3.3. Chapter conclusions are presented in 3.4.

3.1 Definition of the Rebound

Aggregated demand response has several effects on the portfolio of the BRP. As a participant in the market on behalf of a generation and load portfolio the BRP is impacted on several levels due to the rebound effect. The rebound occurs when consumers who have participated in a demand response activation, resume their usual activities at a later time. The rebound has a ripple on the market and the retail profits of the BRP. At the same time, the BRP incurs a penalty if it is imbalanced, which might happen if a third party aggregator takes action upon its portfolio.

In order to do a complete analysis of the effect of demand response on the BRP's portfolio it is necessary to define the rebound effect. It has been recognized in literature but has not been taken into account in the discussions regarding demand response remuneration and balancing responsibility allocation.

The rebound effect corresponds to the additional energy necessary after a requested load reduction [79]. A rebound or payback effect is recognized during dynamic demand side management assuming that if a process is interrputed it might have to 'catch up' later [80]. Deliberate 'load shifting', where consumption is moved from high price hours to low price ones, was proposed in one of the first demand side managements initiatives [53] [81]. A rebound effect is identified when more efficient technologies are at least partly compensated, and sometimes overcompensated, by an increase in energy demand [82]. In demand response modeling it has been found that the consumer's response to an incentive at a certain time period, shifts this energy to later time periods [83]. It was also found that when each indivicual household optimizes its demand to reduce costs the resulting aggregate demand may be affected by an even higher rebound peak shifted toward the off-peak period [84]. It has been shown that simple time-varying electricity price stuctures coupled with automated energy management systems might create pronounced rebound peaks in the aggregate residential demand [85].

In this context the rebound effect is defined as follows:

Rebound effect: the shifting of load from a high price hour to a lower priced hour due to actions of demand response initiated by a consumer or by an aggregator at the consumer's site.

The rebound effect, when optimally achieved, means that the consumer shifts their load to maximize savings from price differences. An example in the commercial segment is the food cold storage facilities that could provide demand response flexibility. The temperature in deep freeze facilities can be modulated within an accepted range taking advantage of low prices to drive temperatures down so that electricity is not needed during high price peak hours. The demand reduction at high priced hours would need to be compensated during low priced hours.

Defining the rebound effect is crucial to creating the whole picture of how the BRP is affected by the demand response actions of the aggregator. The BRP has an impact on it's portfolio due to both, the direct demand response action, and the rebound that comes later.

3.2 Effects of Demand Response in the BRPs' Portfolio

There are two main effects that can be observed for the BRP when a third party aggregator activates demand response on its consumers. An imbalance is created in the wholesale market and the profits of the BRP in the retail market are affected.

- Market Effect: if the BRP has sent a schedule of supply and demand that will be affected by third-party aggregator actions, an imbalance in the DA-market is expected for the BRP. The BRP's profits are affected in different ways depending on whether the BRP has information about the aggregator's actions in advance or not as follows:
  - BRP observes aggregator's actions prior to the market: in this case the BRP can solve its long or short positions in the market itself.
  - BRP doesn't observe the aggregator's actions: if an imbalance is created, and not solved through market actions at day-ahead or intraday level, there will be an imbalance price for not complying with the proposed production and consumption schedules.
- Retail Effect: the BRP's profits depend partly on the retail contracts in place. If actions by the aggregator will change consumer's behavior this will also have an impact on the expected retail profit. This effect will occur in both scenarios of information on the market effect for the BRP.

To illustrate the expected effects of demand response an example is drafted in figure 3.1. In the left half of the figure a demand response reduction is activated during a peak hour. At this moment the BRP had initially forseen to buy 100 MWh to cover the load of its consumers. Due to the unobserved actions of the aggregator upon its consumer's load, the BRP now has a long position, a

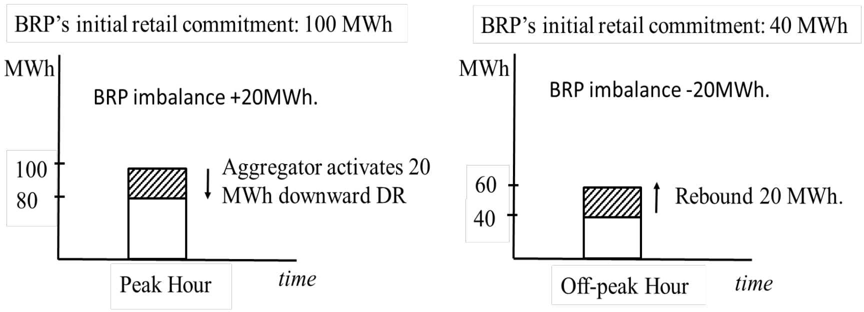

fig. 3.1. Rebound effect illustrative example

positive imbalance, of 20 MWh. In the right half of the picture the rebound effect is illustrated. At a later off-peak hour, consumers compensate for their previously reduced consumption and increase their load by 20 MWh. The BRP had initally foreseen to buy 40 MWh to cover the load of its consumers, but now the consumers are demanding 60 MWh instead. The BRP is short by 20 MWh, it has a negative imbalance of 20 MWh.

3.2.1 Market Effect

The market effect of demand response caused by the rebound is the open position that the BRP experiences due to a third party aggregator action upon it's load portfolio. As mentioned before there are two different ways in which this imbalance affects the BRP depending on whether the BRP has information regarding the actions of the aggregator or not. Figure 3.2 summarizes the imbalance effect on the BRP's portfolio. If the BRP observes the aggregator's actions it can either avoid the imbalance altogether by submitting a modified nomination to the system operator, or it can solve the imbalance in the market itself by buying or selling energy. If the BRP doesn't observe the aggregator's actions the schedule that the BRP submits to the system operator is flawed and the BRP remains imbalanced. Both cases are explained in detail below.

BRP Observes Aggregator's Actions

The BRP has foreseen an amount of load consumption and buys energy at the market price in order to cover it. Figure 3.3 illustrates an example of the market effect for the BRP and the Aggregator. Prices are added to the example in figure 3.1 to illustrate what happens to the BRP's and the Aggregator's profits

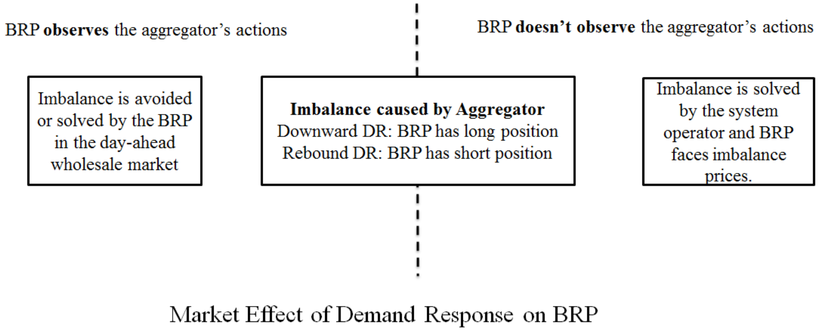

fig. 3.2. Market effect of demand response (DR) on BRP

due to a demand response activation. It is assumed that the aggregator does not have the balancing responsibility. This means that the BRP incurs in market transactions to balance its portfolio in the market. It is assumed that the BRP does not know what the actions of the aggregator are in the DA market, but is settled ex-post at the marginal market price.

A peak hour marginal price of 90 €\MWh and an off-peak hour price of 30 €\MWh are proposed. In the initial scenario without demand response the BRP would have had to procure the energy at 90 €\MWh to cover its entire demand of 100 MWh incurring a procurement cost of 9000 €. After demand response the BRP does not have to procure those 20 MWh, and can save 1,800 €. Later, when consumers rebound, the BRP needs to source that energy at a lower price of 30 €\MWh. The BRP faces an unexpected cost increase of 600 € at the rebound hour. Overall, the market effect is positive, since the BRP sold energy at a high price hour and bought it at a low price hour for a total savings of 1,200 € on the market price.

Generalizing the market effect for the BRP ends up as described in equation (3.1). The market effect, $MKTeff$, of one demand response event for the BRP is equal to the difference between the marginal price at a peak hour, MP_{Ph} and the marginal price at an off peak hour, MP_{OPh} times the amount of demand reduction $down$.

$$MKTeff = (MP_{Ph} - MP_{OPh}) * down \quad (3.1)$$

where

$MKTeff$ market effect of demand response for the BRP [€]

Market Effect for BRP

Peak Hour Price: 90 € / MWh		**Off- Peak Hour Price: 30 € /MWh**	
Marginal Price of Energy	100 * 90 = 9000 €	Marginal Price of Energy	40 * 30 = 1200 €
After Demand Response	80 * 90 = 1200 €	After Demand Response	60 * 30 = 1800 €
Market Cost Savings	20 * 90 = 1,800 €	Market Cost Increase	20 * 30 = - 600 €

Total Effect: 1,800 – 600 = 1,200 € savings on Market Price

Market Effect for Aggregator

Peak Hour Price: 90 € / MWh		**Off- Peak Hour Price: 30 € /MWh**
Market Price Income	20* 90 = 1,800 €	Aggregator doesn't cover rebound

Total Effect: 1,800 € income

fig. 3.3. Market effect example of demand response for the BRP and aggregator

MP_{Ph}	marginal price of the market at a peak hour [€\MWh]
MP_{OPh}	marginal price of the market at an off peak hour [€\MWh]
$down$	amount of demand reduction [MWh]

BRP doesn't Observe Aggregator's Actions

If the BRP is unaware of the actions of the aggregator, its position in the market remains open with respect to its real load and generation profiles. The BRP's nomination, meaning the schedule it submits to the system operator, is faulty by an amount equal to the demand response actions caused by the aggregator. In this case the system operator has to activate reserves to cover the imbalances caused. The BRP then has to face the imbalance pricing according to system rules as explained below.

The imbalance is caused by the activation of upward and downward demand response. Since upward and downward demand response are activated at different hours, the imbalance caused depends on the direction of the activation of this flexibility. The imbalance can be either positive or negative for the BRP as follows:

- Positive imbalance means that injection exceeds off-take. A downward demand response activation leads to positive imbalance, as the planned injection of the BRP will be higher than the actual offtake at that hour.

Imbalance Price Peak : 120 € / MWh		Imbalance Price Off-peak : 90 € / MWh	
Imbalance after DR	20*120 = 2400 €	Imbalance after DR	- 20 * 90 = -1800 €

Total Effect: 2400 – 1800 = 600 € Imbalance market gain

fig. 3.4. Imbalance effect of demand response if BRP's position is left open

- Negative imbalance means that off-take exceeds injection. An upward demand response activation leads to a negative imbalance, as the planned off-take of the BRP will be higher than the injection at that hour.

Continuing with the example presented in figure 3.1, the imbalance effect is illustrated in figure 3.4. In this example, it is assumed that positive and negative imbalance have the same value. A peak price is proposed at 120 €\MWh, which means that the positive imbalance of the long position left by the downward demand response receives 2400 €. This is the product of the imbalance amount 20 MWh and the imbalance price at the peak hour, 120 €\MWh. Conversely, during the off-peak hour when the rebound occurs the imbalance price is set at 90 €\MWh. Which means that the BRP has to pay -1800 € for its short position, the product of -20 MWh corresponding to the rebound effect, and 90 €\MWh.

This is only an illustrative example, the results may vary significantly according to system conditions. Traditionally, a reduction of demand during peak hours would help the system and earn an income. Changing system conditions due to RES growth might change that scenario. A generalization of this effect is therefore not possible, as the system conditions might change.

3.2.2 Retail Effect

The retail effect of demand response in the BRP's profits has two parts. First, the loss of profit for the curtailed energy during the initial demand reduction. Second, the increase in profit when the consumer decides to make up for the lost demand at a later hour during the rebound period. Two cases are presented, one where the consumer faces flat tariffs, and one where the consumer faces peak/off-peak tariffs. Figure 3.5 depicts the effect that the aggregator has on the BRP's retail portfolio. Downward demand response means that consumers decrease their load, while the rebound means that consumers increase it. The BRP's retail income is affected differently depending on the tariff plans that consumers are facing. If they face flat tariffs, the BRP's income is not affected.

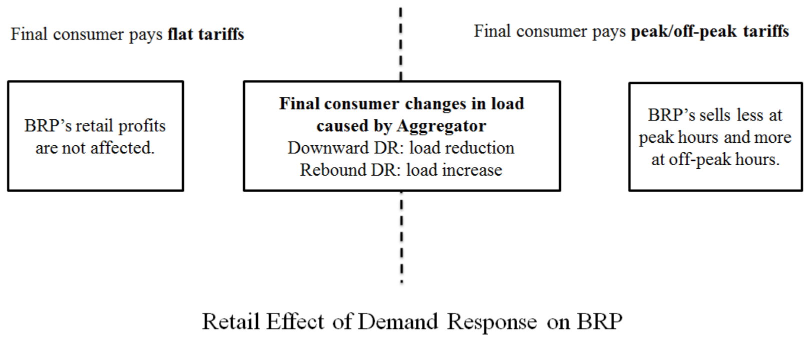

fig. 3.5. Effect of demand response on the retail market

If they face peak and off-peak tariffs the BRP presumably sells less at hours of high prices and more at hours of low prices. Therefore the BRP's income could be negatively affected.

Flat Tariffs

Continuing with the example in figure 3.1, we examine the case where the final consumers providing demand response reduction are facing flat tariffs. The BRP initially foresees 100 MWh load consumption for the appointed period. At a rate of 40 €\MWh the BRP would have earned 4000 € for that energy. Instead, after a demand response reduction of 20 MWh the BRP earns 3200 €, facing a loss of profit of 800 €.

At a later hour, a rebound will take place and the consumers will use the 20 MWh. Since the consumer is facing flat tariffs the cost of the energy is still 40 €\MWh. Therefore at off-peak hour the BRP has an income gain equal to the demand response reduction amount, 20 MWh, times the flat tariff, 40 €\MWh, totalling 800 €. The net effect for of this transaction, for the BRP is neutral, since in the first hour it loses 800 € and in the second it he gains 800 €. This example for the retail effect of demand response is illustrated in figure 3.6.

Peak / Off-peak Tariffs

In this case the aggregated consumers are facing peak / off-peak tariffs of 50 €\MWh for peak hours, and 35 €\MWh for off-peak hours as illustrated in the bottom half of figure 3.6. When the demand reduction occurs in the peak hour the BRP receives 4,000 € instead of the expected 5,000 € before the

Retail Effect with Flat Tariff

Flat Tariff : **40 € / MWh**		**Flat Tariff** : **40 € / MWh**	
Initial Expected Income	100 * 40 = 4000 €	Initial Expected Income	40 * 40 = 1600 €
After DR	80 * 40 = 3200 €	After DR	60 * 40 = 2400 €
Retail Income Loss	20*40 = - 800 €	Retail Income Gain	20*40 = 800 €

Total Effect: -800 + 800 = 0 €

Retail Effect with Peak / Off-Peak Tariff

Peak Tariff : **50 € / MWh**		**Off-Peak Tariff** : **35 € / MWh**	
Initial Expected Income	100 * 50 = 5000 €	Initial Expected Income	40* 35 = 1400 €
After DR	80 * 50 = 4000 €	After DR	60 * 35 = 2100 €
Retail Income Loss	20*50 = - 1000 €	Retail Income Gain	20*35 = 700 €

Total Effect: -1000 + 700 = -300 € income loss

fig. 3.6. Retail effect example of demand response for the BRP and aggregator

demand response event. The expected retail income of the BRP decreases by 20 MW times 50 €\MWh, for a total expected loss of -1,000 €.

Later, during the off-peak period the BRP is expecting an income of 1,400 € for the initially foreseen 40 MWh consumption. After the rebound occurs due to the previously activated demand reduction, the BRP would earn 2,100 €. The retail income gain is 700 €, equal to the demand rebound amount of 20 MWh times the retail tariff of 35 €\MWh at that moment.

The overall retail effect of a consumer facing peak/ off-peak tariffs ends up as the difference between the expected loss of -1000 € during the first period and the expected income of 700 € during the second period. The net retail effect is negative at -300 €.

Generalizing the retail effect for the BRP for a demand reduction event is described in (3.2). The retail effect, $RETeff$, of one demand response event for the BRP is equal to the difference between the tariff the consumer whose load was reduced faces at an off-peak hour, T_{OPh} and the tariff at a peak hour, T_{Ph} times the amount of demand reduction $down$.

$$RETeff = (T_{OPh} - T_{Ph}) * down \quad (3.2)$$

where

$RETeff$ retail effect of demand response for the BRP [€]

T_{OPh} Off-peak tariff that the consumer affected by demand response faces [€\MWh]

T_{Ph} Peak tariff that the consumer affected by demand response faces [€\MWh]

down amount of demand reduction [MWh]

3.3 Proposed BRP-Aggregator Adjustment Mechanisms

It has been established in the previous sections that the actions of a third party aggregator cause open positions for the BRP as demonstrated in figure 3.1. The BRP has a long position, meaning a positive imbalance, when there is an unforeseen demand reduction. In contrast, it has a short position, meaning a negative imbalance, when there is an unforeseen demand rebound.

While in this thesis, the focus is the integration of demand response into wholesale markets the effects described above also apply for cases when demand response is sold into the balancing markets. The current discussions arise from the first implementations of DR in balancing markets, but they are nonetheless relevant within the context of this thesis.

In the three effects described above, it was assumed that the BRP would bear the consequences of demand response. However, there are several different proposals on the table at the moment. The options for allocating the imbalance, and dealing with the imbalance responsibility are discussed next.

The Smart Grid Task Force (SGTF) suggests a financial adjusment mechanism to ensure that all electricity sourced on the market and consumed by end-consumes is paid to the actor who sourced it [66]. The BRP shouldn't face costs incurred through the fulfillment of balancing requirements. Mechanisms should be symmetric for downward and upward demand response. The TSO (or DSO) is placed as a neutral market facilitator between aggregators, BRPs and suppliers, providing communication and settlement services.

In a follow-up document the recommendations further explain specifications of compensation mechanisms relating to demand response activation [86]:

- Demand response activation initiated by a third party should not result in imbalances for the BRP of the involved consumers.
- There should be payments corresponding to sourcing costs:

  - In case of demand reduction: the aggregator should pay the BRP for the sourced energy.
  - In case of demand increase: the BRP should pay the aggregator for the sourced energy.

- The consumer should be billed only what he has actually consumed (unless it is contractually agreed otherwise between consumer and aggregator).
- The sourcing price could be:
  - Bilaterally negotiated between the supplier and a third party aggregator.
  - Set through price formulas to neutrally and accurately reflect sourcing costs.

EURELECTRIC proposes two main market design options to deal with the imbalanced positions of the BRP [5]:

- A bilateral contractual model, by which the BRP and the aggregator agree on compensation.
- A centralized regulated model, where the BRP is compensated by the aggregator at a regulated price.

In a nutshell, the positions of EURELECTRIC and the Smart Grid Task Force, are in the same line as the MP-G debate presented in section 2.4.1. The amount of the compensation, and the specifics of the transactions are not described in detail.

NordREG, the Nordic Energy Regulators analyse four different models for aggregation of demand response [87]:

1. One BRP integrated: supplier and aggregator are one entity.
2. Two BRPs without adjustment: independent aggregator and supplier with balance responsibility on the same connection point without adjustment.
3. Two BRPs with adjustment: Independent aggregator and a supplier BRP act on the same connection point, with adjustment of imbalances and reimbursement of sourcing costs.
4. One BRP and Independent aggregator without balance responsibility.

The report by NordREG assumes that all demand response is sold in the balancing market. They address only upward regulating bids to the TSO (downward demand response). Imbalances are settled on single pricing: the settlement for both positive and negative imbalances is equal to the clearing price of the balancing market.

NordREG supports an option where the BRP and aggregator are integrated, as the most efficient way to enable demand response because it keeps to the principle of one BRP per connection point. They argue that in a competitive retail market customers would have the option of switching to a retailer that offers demand response services. Option 2, where the aggregator and the BRP both have balancing responsibility but are not adjusted, is not viable as the aggregator would not earn a profit since it only sells to cover its imbalanced position. Option 3, where a settlement is made between the aggregator and the BRP, presents practical issues to properly determine the imbalance of every BRP and the correct sourcing costs of the energy. Option 4 creates additional costs for the system because the aggregator is not liable for the imbalances it is causing and therefore is not a recommended option.

France and Switzerland have opted for regulated contracts between the aggregator and BRP, where the aggregator pays a regulated fee to the BRP for demand response reductions [57]. France determines a fee that is equivalent to the retail cost of the sourced energy as explained in section 2.4.2. In Switzerland the aggregator is obliged to compensate the BRP for the difference in consumed energy through a regulated payment that is set by the quarter-hourly day-ahead spot prices of the Swiss electricity index.

In the federal markets of the United States, remunerating demand response reductions at the full wholesale locational market price was chosen as the best option. However, ERCOT, a state non-federal market, still choses to remunerate it at the LMP-G [64]. Several methods for dealing with the cost allocation of demand response reductions were discussed by the FERC [88]:

- Allocating it to the retailer associated to the demand response provider.
- Socializing the costs to all purchasing consumers.
- Assigning part of the costs to the retailer and part to all consumers.
- Allocating the costs to retail consumers who bid demand response into the wholesale market.
- Through a settlement method that incorporates the cost of DR into the dispatch algorithm.

3.4 Conclusions

It is evident in the academic literature that the rebound is a reality, consumers are likely to shift their consumption to another time when they have gone through a demand reduction event. Consumers would shift consumption to a moment when the price of electricity is lower. Current discussions on demand remuneration at a regulatory level, however, do not take into account the rebound effect. It has an effect on the balancing perimeter of the BRP if nothing is done to correct it.

It is necessary to take into account that demand response is an intermediated market. During explicit demand response it is the aggregator who decides when to sell demand response. The aggregator must take the consumer's flexibility availability into account when making decisions about demand reduction. The activation of demand response curtailment causes open positions on the BRP's portfolio. The first open position occurs when the demand response is first activated, the BRP has a long position corresponding to the amount of the activation. The second open position is caused by the rebound when the consumer makes up for the lost energy. In this case, the BRP has a short position corresponding to the amount of the activation.

In the examples presented the way the imbalance is settled depends on whether the BRP observes the actions of the aggregator prior to the day-ahead wholesale market or not. If the BRP observes the actions of the aggregator it can adjust its schedule before making nominations of load and generation to the system operator. If the BRP does not observe the actions of the aggregator its nominations are incorrect and it has an imbalanced position towards the system operator.

In the wholesale market, demand response causes a price arbitraging effect as there is a need to sell when prices are high and buy when when prices are low. There is still a debate as to who should be attributed this effect. If in fact a settlement is suggested it is also possible that the market effect be assigned to the aggregator. Perfect arbitraging might not always be possible if consumers are assumed to rebound between a determined time period. A dynamic modeling approach would shed light on what happens when this is the case.

When the BRP does not observe the actions of the aggregator, the position of the BRP is not corrected and thus left open. In this case the BRP incurs the imbalance fee or penalty depending on the case. Under current imbalance prices, which more or less follow the direction of the market prices, it would appear that the BRP earns a profit through the open position. The imbalance caused by downward DR leaves the BRP with a long position that corresponds to a positive imbalance and is remunerated as upward regulation when sold to the system operator. The imbalance prices themselves depend on the situation of the system and may vary unexpectedly if there is a lot of RES generation at a certain hour. Too much RES generation at a given moment can mean that the system might need downward regulation, or an increase in demand, in order to avoid RES curtailment. Therefore, while under current scenarios it might appear that this imbalance effect is positive for the BRP, the situation might change in the future.

Demand response also has an effect on the retail market. When facing flat tariffs the final consumer would not be motivated to engage in demand response. He might only be motivated to do it if he were receiving an incentive directly from the market, or a profit sharing scheme from the aggregator. When facing peak/off-peak tariffs the final consumer would reap a savings from engaging in demand response. Likewise this has an impact in the total profits of the BRP. The intuitive examples presented in section 3.2.2 imply that the BRP would be at a loss on the retail side if this were the case. Nevertheless, it is important to take into account that the two-tiered peak/off-peak tariffs that consumers face do not directly represent the highest and lowest marginal prices observed in the market. Similarly, the rebound may or may not occur all at the same time, it is possible that the rebound takes place over a different amount of hours than the initial demand reduction took. A dynamic analysis through time is needed to determine the true retail effect of demand response in the BRP's profits.

In chapter 4 the effect on the BRP's and aggregator's profits of the following demand response remuneration proposals are analyzed:

- Day-Ahead market effect: if the BRP has sent a schedule of supply and demand that will be affected by third-party aggregator actions, an imbalance in the DA-market is expected for the BRP. The BRP's profits are affected in different ways depending on whether the BRP has information about the aggregator's actions in advance or not as follows:
  - The BRP observes the actions of the aggregator before the day-ahead wholesale market under the following settlement mechanisms:
    - Full MP: The BRP has balancing responsibility and covers the imbalanced position at the market Marginal Price. The aggregator receives the full MP.
    - MP-G: The Aggregator has balancing responsibility and covers the imbalanced position at a regulated price G representative of the sourcing costs of the energy sold as demand response.

  - The BRP does not observe the actions of the aggregator and the BRP's imbalanced position is left open. The attribution of this imbalance is studied in chapter 4 as follows:
    * The imbalance is attributed to the BRP.
    * The imbalance is attributed to the Aggregator.
    * The imbalance is neutralized by the system operator and its costs are socialized.

- Retail Effect: the BRP's profits depend partly on the retail contracts in place. If actions by the aggregator will change consumer's behavior this will also have an impact on the expected retail profit. This effect will occur in both scenarios of information on the market effect for the BRP.

The options presented are not exhaustive, but they are the most popular ones being discussed and implemented. The current discussions about these alternatives are mostly argumentative in nature. The rebound effect must be taken into account to get the full picture of the consequences of demand response. In chapter 4, a model to analyze each effect more in depth is proposed. The model sheds light on what the rebound effect means for each actor, and how the balancing responsibility proposed in each option affects the profits of the aggregtor and the BRP.

Chapter 4

Modelling the Effects of Demand Response in the Wholesale Market

This chapter is an empirical analysis of the effects of demand response in the wholesale market. Demand Response has been placed within market design in chapter 2 and its effects have been analyzed in chapter 3. It was concluded in chapter 3 that a dynamic analysis of the effects of demand response in the wholesale market is needed. The rebound effect has not been taken into account into the remuneration discussions in place. In order to analyze it, a simulation model is proposed. The model accounts for the rebound in the market costs and profits of each party. This chapter proposes an extension of the unit commitment model in order to present the optimal merit order of generation in the presence of demand response. The traditional model is modified to include participants as portfolio owners. The BRPs are represented as owners of generation and holders of retail obligations. The aggregator is introduced as the supplier of all demand reductions offered in the market. Continuing in the framework of the previous two chapters, only demand reductions are studied as a service in order to keep the analysis simple.

The aggregator is qualitatively placed within a modelling framework in section 4.1. A decision making model including demand response, and a portfolio balancing BRP is introduced in section 4.2. A wholesale market case study is setup and analyzed in section 4.3. The effect of demand response in BRP and Aggregator Profits is explored in section 4.4. Chapter conclusions are presented in 4.5.

4.1 Aggregator and Demand Response Modelling

A survey of electricity market modelling classifies models as simulation models, equilibrium models considering different firms, and one firm optimization models [41]. A survey of agent based market models that take into account the objectives of different participants can be found in [89].

Demand response has been integrated into electricity market models in numerous articles in the literature. A comprehensive study of demand response models based on control mechanism, time-based motivations, and incentive-based demand response can be found in [67]. Demand elasticity is introduced into account in a pool market to model strategic behavior of electricity producers [90]. Demand response considering curtailable loads is introduced in [91]. Demand response in the unit commitment is modedelled in [92] and [81].

In [93] the aggregator is modeled as a retailer and flexibility service provider. In the day-ahead spot market the aggregator buys electrical energy for its clients. The aggregation provides flexibility from different types of residential loads such as air conditioning units, electric vehicles (EVs), water heaters and refrigerators. The model takes into account thermal environmental criteria and consumer comfort. The TSO and DSO then validate the aggregator's bids and correct them in case of congestions. The model considers only the day-ahead spot market. Their results show that flexible bidding reduces the average cost and the energy purchased by the aggregator in the market.

In [94] it is stated that when consumers modify their consumption behavior incentivized by DR programs they incur a cost. It could be either the cost of running a local generator for an industrial consumer, or the loss of comfort for a household consumer. A mechanism that takes into account this cost from a centralized system perspective is proposed considering hidden information and agent rationality. The model proposed fixes system demand for flexibility and proposes pricing and quantity setting structures in a reserves-type market organized by a centralized decision maker. The current analysis, in contrast, places the aggregator as a profit maximizing entity in the day-ahead and intraday wholesale electricity markets and determines what the outcome would be given different costs of providing flexibility. In the case of the aggregator the cost of providing flexibility is the contracting and transactional cost of the energy plus any fees added by the regulators.

In [79] the authors calculate the bidding price that optimizes the total income of the aggregator taking into account three rebound scenarios of 0, 50, and 100 percent of the total demand reduction using price data of the French day-ahead and intraday markets. Aggregator profits are calculated on a marginal price basis in the day ahead market and a pay-as-bid basis in the balancing market. The profits are then the offer price minus a compensation that must be paid to the supplier of the consumer times the amount of energy decreased minus the rebound energy. In their model, the aggregator is also responsible for paying the energy increase of the rebound effect at a regulated imbalance price. It is concluded that participation in energy-only markets is not enough to cover investment costs for aggregation. Arbitrage between the day-ahead and balancing markets is taken into account. However, the authors assume that the aggregator holds perfect knowledge over the prices of both markets, and that demand response will not have an effect on price. These two assumptions lead to an overvaluation of estimated aggregator profits, as demand response has a price lowering effect on markets.

The authors maximize aggregator profits through simultaneous bidding of V2G energy and ancillary services in [95]. Aggregator revenues are obtained from a fixed rate on energy delivered to the EV, the revenues from selling regulation and spinning reserves, and revenues from selling energy. Aggregator costs from performing V2G are the wholesale cost of energy delivered to the vehicle and the battery degradation associated from discharging. Consumer preferences regarding the state of charge of the EV are taken into account. In [96] the aggregator provides reserve capacity through unidirectional V2G. Aggregator profits come from a fixed markup over market price on energy which is passed on to the consumers plus a fixed percentage of the revenue obtained from providing regulation services. These two models do not consider the effect of demand response on the market or reserves prices, nor its effect on other market participants.

The effect of vehicle aggregation for reserves provision on the day-ahead an intraday schedules is modeled in [97]. The authors show that the system can absorb higher levels of EV penetration without expansion when there is coordination between the charging schedule and the system operator. The revenue of the aggregator is a sensitive parameter in the optimization. The aggregator sells energy or capacity to the system operator at a fixed price per MWh or MW respectively. The financial implications and interactions with other market participants are not taken into account. Market based control of electric vehicles by an aggregator is studied to identify when it conflicts with the operational constraints of the distribution grid [98].

Several approaches consider the aggregation of demand for system purposes without a financial objective function for the aggregator. An approach that considers aggregated loads for reserves provision can be found in [99] where price considerations are left out in preference for loads that track a signal of the current state of the system. In [100] a control strategy for aggregated air conditioning loads is designed in order to provide system services such as frequency regulation and peak load reduction. Other examples of direct load control strategic modeling can be found in [101] and [102].

Demand response has been successfully modelled though many different mechanisms in the literature. The aggregator as a market participant, has not been widely studied. The main literature on aggregator modelling refers to optimizing the aggregator-end customer relationship, and not to the aggregator-market relationship. A lack of analysis of the effects of aggregation on the market, and the financial transactions of the other market participants is evident. Therefore this thesis extends existing integrations of demand response into market models to simulate the effects of aggregation on other market participants under different demand response pricing regimes.

4.2 Model Description

A centralized decision making algorithm is chosen to represent the perfect scenario of demand response integration into the market merit order. Demand response is modelled as a demand reduction that is remunerated and a demand rebound that must pay the market price. Demand reduction is allocated to an aggregator actor. BRPs are introduced as owners of generation assets and load portfolios that must be satisfied. The traditional unit commitment model including demand response [55] is extended to include financial transactions of the BRPs who either produce with own resources or buy energy from other BRPs or the aggregator to satisfy their load commitments.

For every time step t a decision is taken first on the wholesale market regarding the generation schedule of each BRP and the demand response activation per aggregator. BRPs have a portfolio of conventional generation units, and RES availability. They are in charge of covering a specific portion of demand. A BRP must either generate, or buy, the energy needed to cover the load pertaining to a portfolio of consumers.

The day ahead formulation describes the selection of generation units satisfying the entire demand. At the same time the portfolio of each BRP is balanced in such a way that its own generation plus any purchases minus any sales satisfy its demand. The actors defined in the problem are the BRPs denoted by *f*, and the aggregator *ag*.

The day-ahead market is defined by a cost minimization in (4.1). Each BRP *f* is defined for a portfolio of generation units and must satisfy a certain demand as a supplier. The amount of energy generated $g_{f,t}$ [MWh] is an output variable of the model. Each BRP must pay marginal costs of generation defined by MC_f. In addition BRPs incur startup costs $scosts_{t,f}$ for firing up their generation units. Curtailment, in case of excess availability for both wind $curtw_{f,t}$ and PV $curtpv_{f,t}$ not needed, carries a fixed fee CC. Downward demand response has a transfer payment cost for the aggregator of G. The problem is subject to the constraints defined by (4.2) to (4.11) pertaining to generation constraints, demand response constraints, and BRP constraints.

$$\min \sum_{t,f} \{(g_{t,f} * MC_f + scosts_{t,f} + CC * (curtw_{t,f} + curtpv_{t,f}) + \sum_{ag,t,f} (down_{ag,t,f} * G)\} \tag{4.1}$$

where

$g_{t,f}$ energy produced in time t generator f [MWh]

MC_f marginal costs per generator f [€\MWh]

$scosts_{t,f}$ start up costs decision variable in time t per generator f [€]

CC cost of RES curtailment [€\MWh]

$curtw_{t,f}$ curtailment of excess wind energy at time t owned by BRP f [MWh]

$curtpv_{t,f}$ curtailment of excess PV energy at time t owned by BRP f [MWh]

$down_{ag,t,f}$ downward demand response [MWh]

G transfer payment cost for aggregator for providing downward demand response [€\MWh]

4.2.1 System Balance

The system balance equation that sets generation equal to demand is given by (4.2). Demand $D1_{t,f}$ is defined per BRP f and per time period t. Conventional plant output $g_{t,f}$ is added to wind production $WIND_{t,f}$ and PV production

$PVfda_{t,f}$. PV and wind profiles are input data. Wind and PV curtailment are decision variables $curtw_{t,f}$, and $curtpv_{t,f}$ respectively. Curtailment is subtracted from the input wind and PV profiles when there is excess production that is not needed, and it can occur simultaneously for both PV and wind. In addition to conventional generation RES output the equation includes a component of demand response, adding downward demand response $down_{ag,t,f}$ and subtracting upward demand response $dup_{ag,t,f}$. In a single period of time there will be either downward or upward demand response, but not both. Thus, the system balance equation is defined as:

$$\sum_{f}(g_{t,f} + WIND_{t,f} - curtw_{t,f} + PVfda_{t,f} - curtpv_{t,f})$$

$$+ \sum_{ag,f}(down_{ag,t,f} - dup_{ag,t,f}) = \sum_{f} D1_{t,f} \qquad \forall t \qquad (4.2)$$

where

$g_{t,f}$ amount of energy produced in hour t per BRP f [MWh]

$WIND_{t,f}$ input wind generation in hour t per BRP f [MWh]

$PVfda_{t,f}$ input PV generation in hour t per BRP f [MWh]

$dup_{ag,t,f}$ upward demand response per aggregator ag in hour t affecting BRP f [MWh]

$D1_{t,f}$ input load profile in hour t per BRP f [MWh]

4.2.2 Generation Constraints

Equations (4.3) and (4.4) set the value of generation output within each unit's limits $PMIN_f$ and $PMAX_f$ when each unit is on as given by the binary variable $z_{t,f}$. Start-up costs $scosts_{t,f}$ are given by (4.5) whenever the binary variable $z_{t,f}$ changes from 0 to 1.

$$z_{t,f} * PMIN_f + g1_{t,f} = g_{t,f} \qquad \forall t, f \qquad (4.3)$$

$$(PMAX_f - PMIN_f) * z_{t,f} \geq g1_{t,f} \qquad \forall t, f \qquad (4.4)$$

$$SC_f * (z_{t,f} - z_{t-1,f}) \leq scosts_{t,f} \qquad \forall t, f \qquad (4.5)$$

where

$g1_{t,f}$ amount of energy produced per generator above minimum output for hour t per BRP f [MWh]

$PMAX_f$ maximum output per generator per BRP f [MWh]

$PMIN_f$ minimum output per generator per BRP f [MWh]

$z_{t,f}$ binary variable of unit commitment in time t for BRP f

$scosts_{t,f}$ start up costs decision variable in time t per BRP f [MWh]

4.2.3 Demand Response Constraints

Up and downward limits $PMAXag_{ag}$ for demand response are given by (4.6) and (4.7). Similar to generation they are subject to an on or off state defined by a binary variable $v_{ag,t}$ for downward and $u_{ag,t}$ for upward demand response. Equation (4.8) ensures that up and downward demand response are not activated during the same hour. Equation (4.9) ensures that demand will be shifted during a subset st of the entire time evaluation period t, such that upward demand response is equal to downward during that period.

$$down_{ag,t,f} \leq PMAXag_{ag} * v_{ag,t} \qquad \forall ag, t, f \qquad (4.6)$$

$$dup_{ag,t,f} \leq PMAXag_{ag} * u_{ag,t} \qquad \forall ag, t, f \qquad (4.7)$$

$$v_{ag,t} + u_{ag,t} \leq 1 \qquad \forall ag, t, f \qquad (4.8)$$

$$\sum_{st} \{dup_{ag,t,f} - down_{ag,t,f}\} = 0 \qquad \forall ag, f \qquad (4.9)$$

where

$PMAXag_{ag}$ maximum output of demand response for aggregator ag [MWh]

$u_{ag,t}$ binary decision variable for upward demand response per aggregator ag in time t

$v_{ag,t}$ binary decision variable for downward demand response per aggregator ag in time t

4.2.4 BRP Constraints

Finally, (4.10) and (4.11) pertain to the BRP. These constraints form the contribution of this thesis to current modelling. They are purely financial constraints representing operations between BRPs to buy and sell energy at the best price possible.

In (4.10) the BRP ensures that it's demand $D1_{t,f}$ is covered by either of generation $g_{t,f}$, wind availability minus curtailment, as well as PV availability minus pv curtailment, plus the variable purchases $pur_{t,f}$ from other BRPs. Alternatively if a BRP has an excess of cheap generation it can sell (variable $sales_{t,f}$). Equation (4.11) ensures that sales and purchases for each period of time t add up to zero as they are purely financial transactions.

$$\begin{aligned} & g_{t,f} + WIND_{t,f} + PVfda_{t,f} - curtw_{t,f} - curtpv_{t,f} \\ & - sales_{t,f} + pur_{t,f} - D1_{t,f} \\ & + \sum_{ag} (down_{ag,t,f} - dup_{ag,t,f}) = 0 \qquad \forall t, f \end{aligned} \tag{4.10}$$

$$\sum_{f} \{sales_{t,f} - pur_{t,f}\} = 0 \qquad \forall t \tag{4.11}$$

where

$sales_{t,f}$ sales in time t per BRP f [MWh]

$pur_{t,f}$ purchases in time t per BRP f [MWh]

4.2.5 Profits Calculation

The profits of each participant are calculated taking into account their income and expenses. The actions of the aggregator upon the portfolio of the BRP cause an imbalance in the BRP's portfolio. The assignment of this imbalance to either the Aggregator or the BRP will affect the profits of each one respectively. In the sections below the aggregator and BRP profits are discussed with and without the need to pay for the imbalance effect.

Aggregator Profits

The Aggregator profits are calculated following (4.12). The aggregator makes an income at the market price for downward demand response. This value is decreased by the transfer payment G for downward demand response $down_{ag,t,f}$, and its own cost of aggregating demand response c_{ag}. In the analysis that follows, this value is assumed to be a constant scalar, and therefore set at value zero for simplicity. This is the profit expected when the aggregator is not responsible for covering imbalance costs.

$$Profit_{ag} = \sum_{t,f} \{lambda_t * down_{ag,t,f} - G * down_{ag,t,f} - c_{ag} * down_{ag,t,f}\} \tag{4.12}$$

where

λ_t market price in time t [€\MWh]

$down_{ag,f,t}$ amount of downward demand response per aggregator ag belonging to BRP f in time t [MWh]

G transfer pricing G of providing demand response for the aggregator [€\MWh]

c aggregator's own cost of providing demand response [€\MWh]

BRP Profits

The imbalance caused by the aggregator is covered in the day ahead market through purchases and sales of energy that compensate for demand response upward and downward actions. This case assumes perfect information ex-ante by the BRP on the actions of the aggregator.

Case where BRP assumes balancing Responsibility:

Total BRP profits comprise the addition of two different concepts:

- DA Market Profits: composed by sales and profits in the day ahead market multiplied by the market price λ_t minus the costs of providing energy with a portfolio of generation represented by $gen_{t,f}$ as seen in equation (4.13) below.

$$MKT_f = \sum_t \{\lambda_t * (sales_{t,f} - pur_{t,f}) \\ - MC_f * g_{t,f} - scosts_{t,f} + \sum_{ag}(G * down_{ag,t,f})\} \quad (4.13)$$

where

λ_t	market price in time t [€\MWh]
$sales_{t,f}$	sales in time t per BRP f [MWh]
$pur_{t,f}$	purchases in time t per BRP f [MWh]
MC_f	marginal costs per generator f [€\MWh]
$g_{t,f}$	energy produced in time t generator f [MWh]
$scosts_{t,f}$	start up costs decision variable in time t per generator f [€]

- Retail Market Profits: composed by demand portfolio sold to consumers by the BRP multiplied times the price of energy to consumers $RETC_f$. The imbalance effect caused by the aggregator is then taken into account by the second part of the equation, where a loss of profit is considered when there is downward demand response $down_{ag,t,f}$ and an increase when there is upward demand response $dup_{ag,t,f}$. Equation (4.14) defines the BRP's retail market profits.

$$RET_f = \sum_t \{D1_{f,t} * RETC_f \\ - \sum_{ag}((down_{ag,t,f} * RETC_f + dup_{ag,t,f} * RETC_f) \quad (4.14)$$

where

$D1_{t,f}$	input load profile in hour t per BRP f [MWh]
$RETC_f$	retail price of energy to final consumers per BRP f [€\MWh]

The effect of the aggregator is neutralized, adds up to zero, under perfect shifting conditions and if the BRP charges a flat tariff to consumers. It is not the case if the BRP would charge dynamic prices to consumers, be it in the form of peak/off-peak tariffs or direct exposure to market prices. It is assumed that the BRP is selling either directly to a portfolio of consumers and acting as a retailer, or to a retailer. Either way the same analysis applies for the point of view of the BRP.

4.3 Wholesale Market Case Study

The model described above is tested in a study case inspired on data for Belgium. One year, 2015, is chosen for the simulations, and input load, wind and PV profiles are used. Four BRPs are proposed, owning different generation resources and a portfolio of load that they need to cover. BRP1 and BRP2 are baseload owners, BRP3 owns both wind and PV generation, and BRP4 owns peaking generation. BRP3 is designated as the owner of all WIND and PV resources in order to be able to study variations separately. One aggregator is modelled as a seller of demand response that affects the supply profile of BRP3.

In order to simplify the study the following assumptions are made:

- Perfect competition and perfect information is assumed, therefore the market clearing price will equal the cost of the most expensive unit producing at a certain time period. Thus, a study based on an economic dispatch model represents the market outcome accurately.
- A rebound of 100% is expected within a 24 hour horizon.
- Each BRP represents both retail and supply.
- The rebound occurs at the best possible moment.
- All of the wind and PV generation is traded in the DA market.
- Only downward demand response is remunerated as a service, upward demand response must pay the cost of the energy used.
- The aggregator is an intermediary assumed to have contracts set in place with final consumers who can provide flexibility, such as households and small businesses.

4.3.1 Input Data

The input data for one year is used. Data for 2015 is represented in figure 4.1. The top chart represents the volume of energy traded in the DA market on Belpex. The center and bottom charts represent the Wind and PV profiles for the same period respectively.

BRP characteristics

BRPs have a portfolio of generation technology and demand that each must satisfy. The model calculates the dispatch for each generation technology,

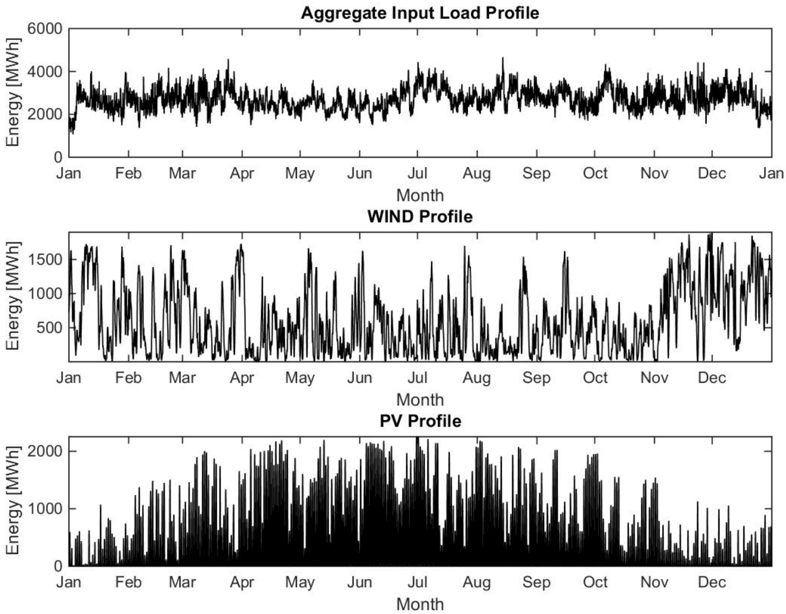

fig. 4.1. Input data for 2015: energy traded in DA Belpex market (top), wind profile in Belgium (center), PV profile in Belgium (bottom)

BRP1 has two, BRP2 has two, and BRP3 and BRP4 have only one generation technology. Fuel prices form the basis for marginal costs [103]. Table 4.1 shows generation fuel costs per technology, prices were converted to euros, at an exchange rate of 0.75 €per $, following the convention used by [103]. Start-up costs and minimum power criteria, the last two columns of table 4.1 were inspired by [104].

Each BRP has certain generation technologies installed, as seen in table 4.2. The prices used in table 4.1 are rounded for simplicity and used to represent different generation technologies that the BRPs own. In order to isolate the effect of RES in the BRP profits, BRP3 owns all wind and PV resources.

The BRP price to consumers, meaning the retail price collected from retail sales, is assumed to be 40 €\MWh, based on an tariff calculator for the Belgian market [105]. This price is debatable as other data assume a retail tariff of 22 €/MWh (rounded from value= 22.1) based on [1]. The chosen value better reflects the current situation that consumers are facing since it is based on an

Technology type	Fuel, waste and carbon costs $\MWh	Fuel, waste and carbon costs in €\MWh	Start-up Cost [€\Δ MWh]	Minimum Power [% of Installed Capacity]
Combined cycle gas turbines	84.70	63.5	22	35%
Open cycle gas turbines	114.92	86.19	6	30%
Coal ultra-supercritical	48.72	36.5	13	35%
Nuclear	14.15	10.61	10	45%

Table 4.1. Levelised costs of electricity for generating plants

BRP	Generation Resource	Marginal Cost €\MWh	Start-up Costs [€]	Minimum Power [MW]	Installed Capacity [MW]
BRP1	BRP1g1	10	5400	540	1200
	BRP1g2	37	4550	350	1000
BRP2	BRP2g1	37	3185	245	700
	BRP2g2	63	5390	245	700
BRP3	BRP3g1	86	5390	207	690
	BRP3W	0	0	0	1950
	BRP3PV	0	0	0	2280
BPR4	BRP4g1	86	720	120	400

Table 4.2. Cost and installed capacity of generation per BRP

average of company per company data.

Aggregator characteristics

The aggregator can provide demand response flexibility of 200 MW, which is equivalent to about 5% peak load. The aggregator is subject to paying the transfer payment 'G' to the BRP. The value of 'G' is analyzed based on different scenarios.

Scenario	**Transfer Payment Value [€\MWh]**
No Transfer Payment	0
Transfer Payment 1	30
Transfer Payment 2	45

Table 4.3. Transfer payment scenarios analyzed in detail

Scenario Creation

A sensitivity analysis is conducted to test for different values of the transfer payment 'G' from the aggregator to the BRP. Three main prices are proposed based on the reference values used in the french market initiative NEBEF during 2016 [77]. The analysis is done for a flat transfer payment rate as described in table 4.3. The model is run different times changing the transfer payment value represented by DR in the objective function (4.1). The sensitivity analysis is extended to values ranging from 0 to 100 €\MWh in 5 € increments in order to see its full effects on the decisions of stakeholders.

4.3.2 Results of Demand Response in the Wholesale Market

Generation Profile and BRP Transactions

Figure 4.2 presents the generation profile per BRP, for the evaluation period. The results show, predictably, that the cheapest generation units belonging to BRP1 and BRP2 generate as baseload, and the most expensive ones belonging to BRP3 and BRP4 generate only during the peaking periods. BRP3 as the owner of PV and wind generates when the resources are available. Following this same trend, figure 4.3 presents the financial exchanges of energy between the BRPs for purchased energy, while figure 4.4 represents the sales of energy from one BRP to the other. Each BRP must cover a portion of demand, and therefore seeks to buy the output from the cheapest generation units or generate with its own units when necessary. The baseload owners, BRP1 and BRP2 are mostly selling to the peak unit owners BRP3 and BRP4. This last one, BRP4, doesn't sell energy to other BRPs at any time, it either buys energy from other BRPs or uses its own generation to cover its load portfolio. It can also be observed that high amounts of renewable generation displace the conventional technologies at certain time periods.

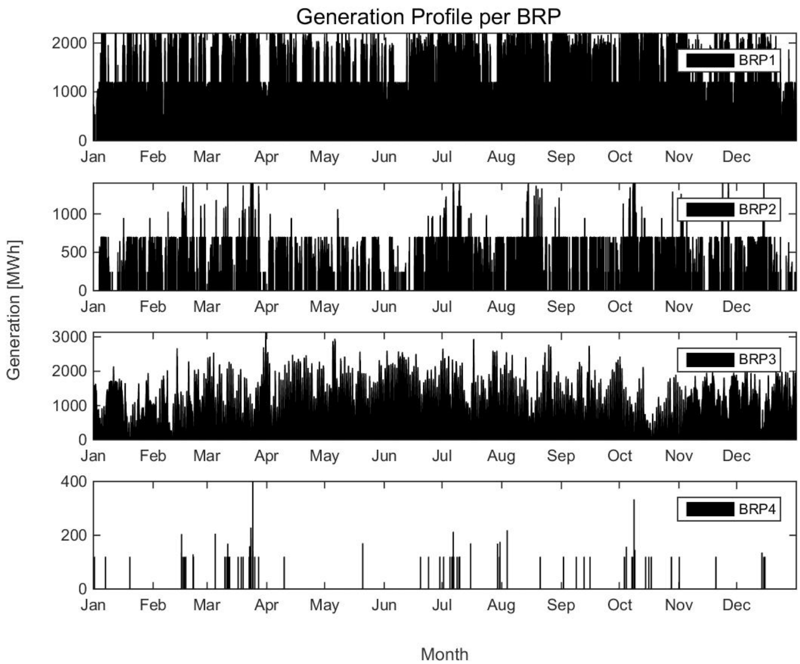

fig. 4.2. Generation profile per BRP for the evaluation period

Demand Response Profile

Demand response is activated downwards when it would be less expensive than the marginal generator. Nevertheless, the shifting constraint has a horizon of 24 hours, which means that the same amount of downward demand response must be activated downward and upwards during a period of 24 hours. Therefore downward demand response is activated at high price hours and upward demand response is activated at lower priced hours. This trend is evident in figure 4.5 where the downward and upward activation of demand response are observed in the upper graph and the market price in the bottom one. It can be observed that downward demand response, equivalent to an increase in generation, is activated at the same hours as the peaks in price during that day, meaning hours 0, 3, 10, 20 and 23. Inversely, upward demand response is activated at hours of lower prices, such as hours 11-13. Upward demand response is also activated during hours 18-19 due to the shifting constraint that forces all downward response to be equal to upward response during one day.

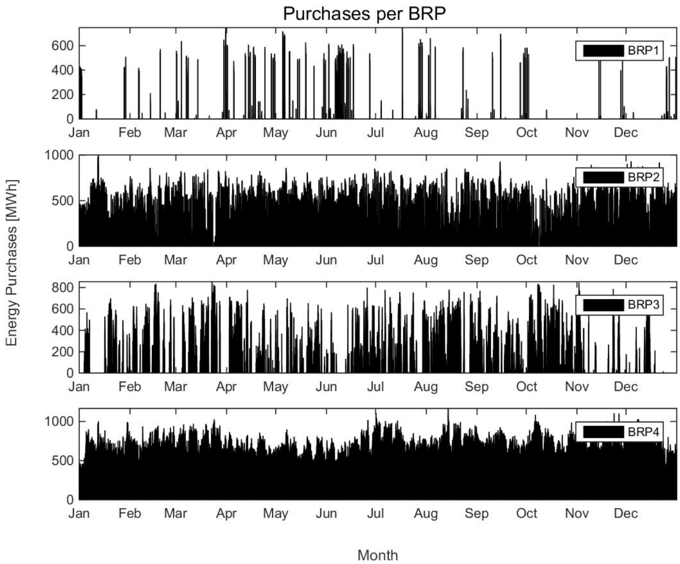

fig. 4.3. Purchases per BRP for the evaluation period

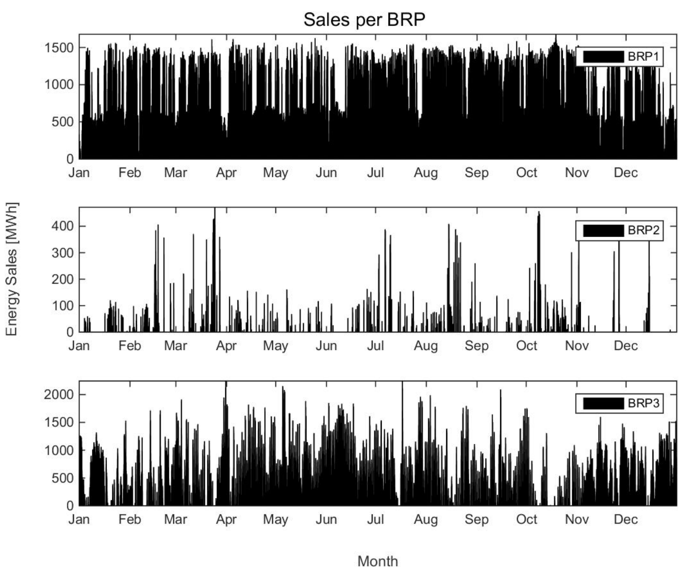

fig. 4.4. Sales per BRP for the evaluation period

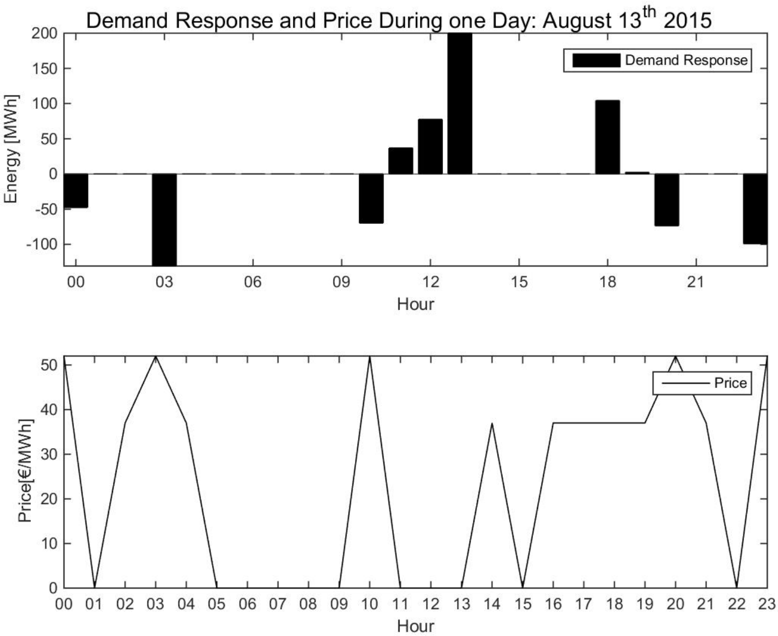

fig. 4.5. Demand response (top) and market price (bottom) activated during one day: August 13^{th}

Market Price

The top graph in figure 4.6 shows the resulting market price λ_t, the dual variable of the balance equation (4.2), for the entire evaluation period. The results follow the marginal costs of generation profile, where the highest cost unit sets the marginal price for the market. A price histogram is presented in bottom graph of figure 4.6. The most common price is 0 €\MWh which means that renewable energy, PV or wind, is the marginal technology setting the price. The second most common price is 36 €\MWh, which is the cost of the coal generators. Negative prices at -30 €\MWh appear when renewable energy would have to be curtailed at the set curtailment cost. This happens because it is cheaper for another BRP to pay to produce than to shut down a unit and have to start it up again at the given start up costs.

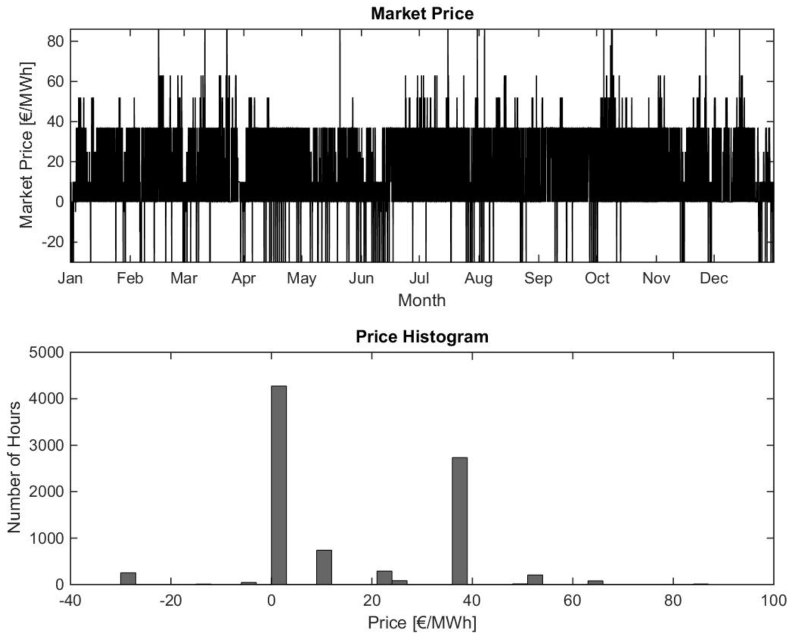

fig. 4.6. Market price per period (top) and price histogram (bottom)

RES Curtailment

Figure 4.7 presents the wind and PV curtailment for the evaluation period. As RES participates at zero marginal cost, and its curtailment is penalized in the objective function, curtailment is not a likely outcome. RES displaces the other types of generation, and is only curtailed in hours when there is very low demand.

4.3.3 Week Studies

In order to take a better look at the different interactions, four case study weeks have been chosen. The weeks were chosen to explain more in detail the interactions between BRPs when there is high or low demand and high or low RES availability. The case studies exemplifies the use of demand response, and the effect of renewable energy on the market transactions.

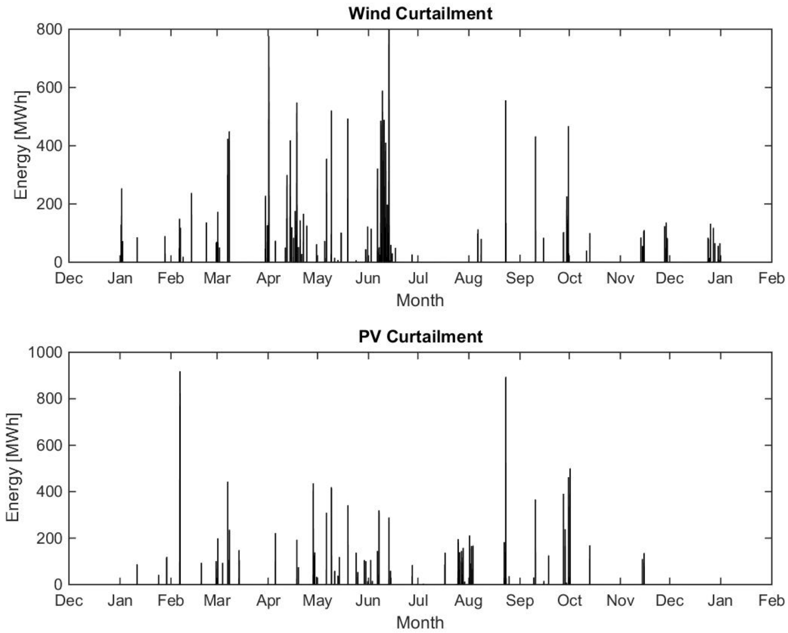

fig. 4.7. Wind and PV curtailment for the evaluation period

- A week with high load in August, containing the day with the highest demand, August 14^{th} 2015.
- A week with low load in January, containing the day with the lowest demand, January 3^{rd} 2015.
- A week with high RES availability, containing the day with the highest RES generation, August 23^{rd} 2015.
- A week with low RES availability, containing the day with the lowest RES generation, April 8^{th} 2015.

High Load Week Results

Figure 4.8 presents the load and results for a high load week. The top graph presents the input load profile. It can be noted that there is a peak in load during Friday August 14th at 8:00 in the morning. At 4668 MWh it is the highest amount of energy demanded in the market during the year.

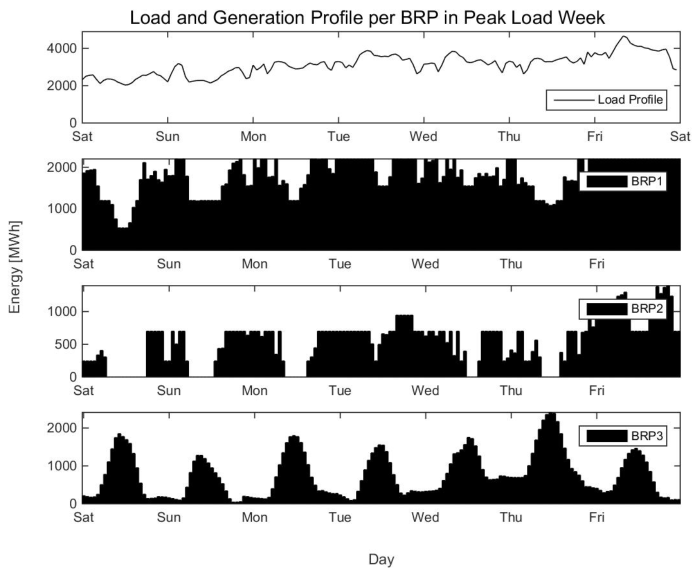

fig. 4.8. High load week generation and load profile

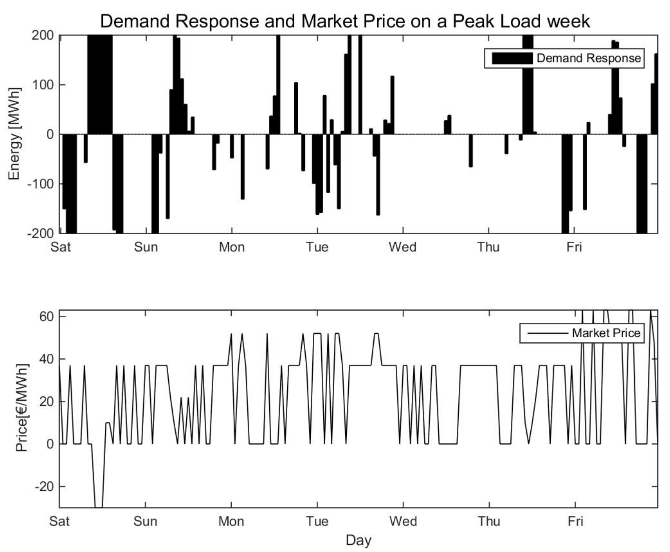

fig. 4.9. High load week demand response and market price

The three bottom graphs in figure 4.8 represent the production profile for BRPs 1, 2 and 3 respectively. BRP4 is not producing during this week as it is not needed, load is covered by the other units, RES and demand response. BRP3 is the owner of the RES resources, wind and PV, their combined profile can be observed in the bottom graph.

Demand Response can be observed in figure 4.9. Upward demand response is activated in periods of high renewable energy availability, especially over the weekend days, Saturday and Sunday. Saturday is a day of lower demand and high RES availability, which leads to negative prices, and therefore the activation of upward demand response since the increase in demand pays the market price. In this case load gets paid to consume. The rest of the week it can be observed that downward demand response is activated at peak price hours and upward demand response corresponds to hours of low prices and high RES availability. However, the demand shifting constraint determines that upward and downward demand must be equal during each period of 24 hours. This causes upward demand response activation at times when there is a price greater than zero.

During high consumption hours, for example the peak observed on friday, the price takes the cost of the second most expensive generation technology owned by a BRP, which is 63 €\MWh. The most expensive, peaking technology is not activated in this case because of the high RES production.

Low Load Week Results

Figure 4.10 presents the results for a low load week. In the same way as the results presented above, the first graph represents the load profile and the remaining three graphs represent the generation profiles of BRPs 1, 2 and 3 respectively. The load reaches its lowest point of demand at 1063 MWh during Saturday January 3$^{\text{rd}}$ at 3:00 am. It can be observed that during low consumption hours this day, only the base load producer and Wind are active. This means that wind has displaced a part of the base load production as well as the second least expensive technology. Demand response can be observed in figure 4.11. Upward demand response is activated during the hours of highest RES availability on Friday. Downward demand response is activated on the same Friday, in order to fulfill the demand response shifting constraint.

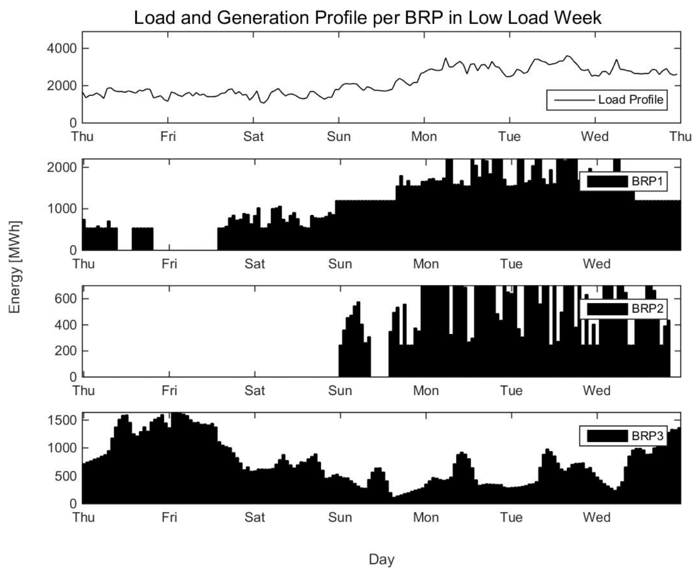

fig. 4.10. Low load week generation and load profile

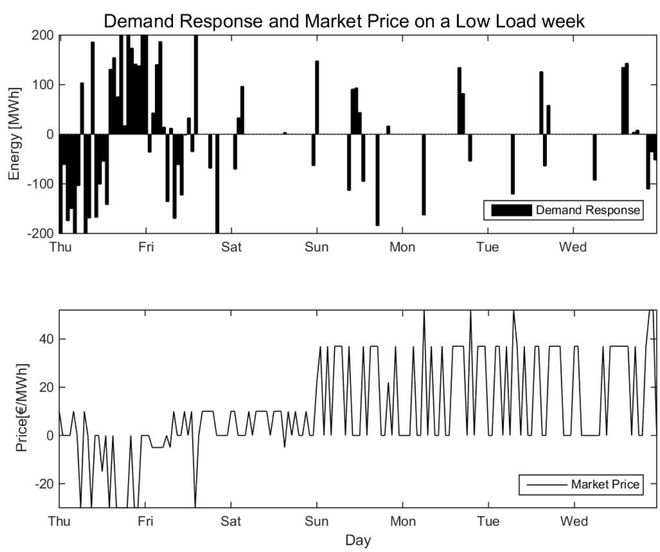

fig. 4.11. Low load week demand response and market price

High RES Week Results

The load profile during the August week is rather constant. Figure 4.12 shows that the high amount of RES generation available from BRP3 is displacing BRP2's generation during lower load hours. BRP4 is not producing at all during this week.

Demand Response can be observed in figure 4.13. Upward demand response is activated to match the hours of highest RES availability, namely PV peaks that occur during the middle of the day. This activation matches low market prices caused by RES. Downward demand response is activated mainly during peak price hours, and at times when there is less RES availability in order to fulfill the 24 hour shifting constraint.

Low RES Week Results

Figure 4.14 shows that BRP1 and BRP2 are generating more energy than in the previous case of high RES availability. BRP4 remains outside of the market results, and therefore buys energy from other BRPs in order to cover its load portfolio. Demand response and market price are seen in figure 4.15 following the same trend as in the earlier study cases. Downward DR is activated at times of higher priced hours and vice-versa.

4.4 Demand Response Effect in BRP and Aggregator Profits

As mentioned in chapter 2, demand response has two effects on the BRP's portfolio. In sections 4.4.1 and 4.4.2 the results of the model are analyzed based on the identified effects of demand response. For reference, the two effects are described below once more:

- Market Effect: if the BRP has sent a schedule of supply and demand that will be affected by third-party aggregator actions, an imbalance in the DA-market is expected for the BRP. The BRP's profits are affected in different ways depending on whether the BRP has information about the aggregator's actions in advance or not.
- Retail Effect: the BRP's profits depend partly on the retail contracts in place. If actions by the aggregator will change consumer's behavior this

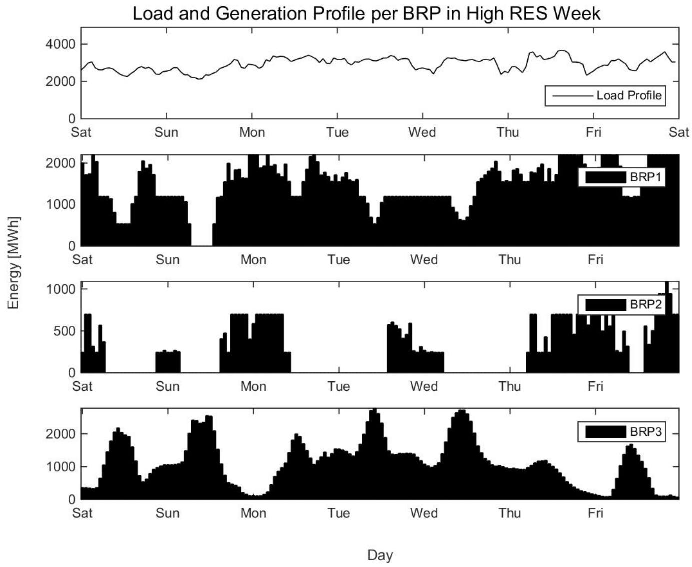

fig. 4.12. Generation and load profile with High RES availability

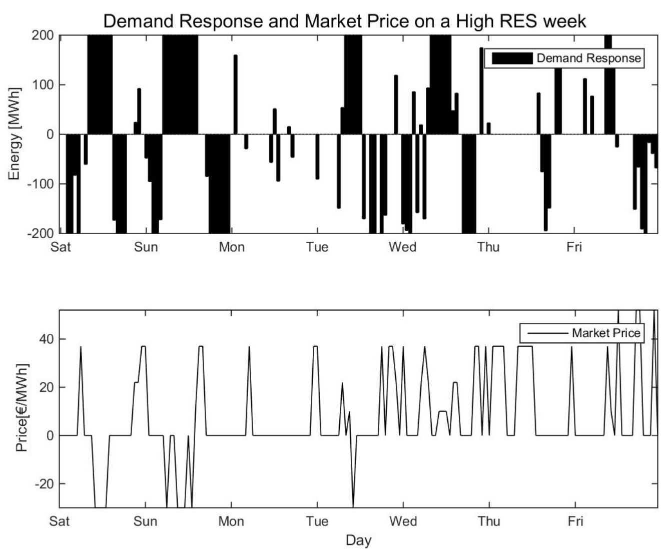

fig. 4.13. Demand response and market price with High RES availability

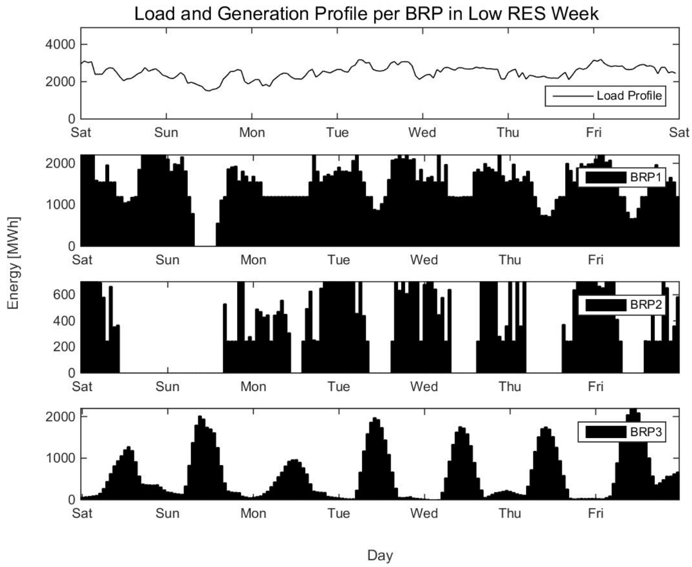

fig. 4.14. Generation and load profile with low RES availability

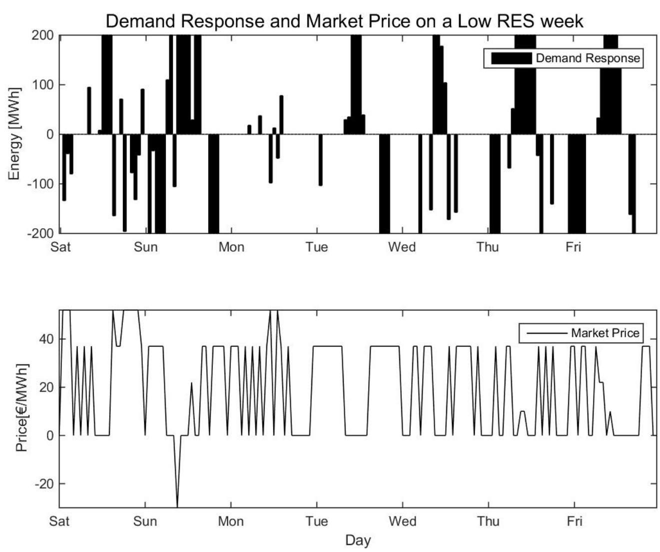

fig. 4.15. Demand response and market price with low RES availability

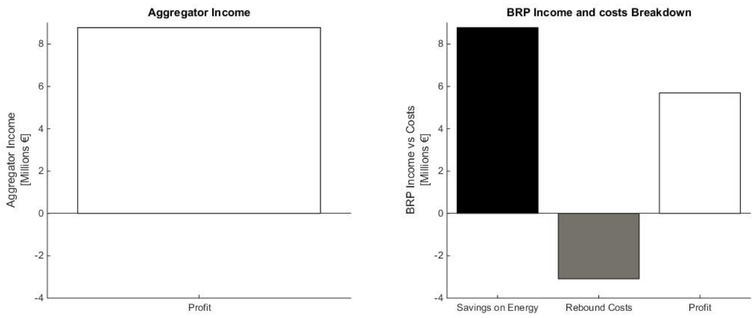

fig. 4.16. Profits of the aggregator (left) and the BRP (right) when the aggregator receives the Full MP for downward demand response

will also have an impact on the expected retail profit. This effect will occur in both scenarios of information on the market effect for the BRP.

4.4.1 Market Effect

The market effect of demand response was identified in section 3.2.1 of chapter 2. It is caused when the aggregator's activation of downward demand response cause a long position for the BRP, and later the rebound causes a short position. The different proposals for analyzing the effect of demand response depend on whether the BRP observes the actions of the aggregator or not.

The BRP Observes the Actions of the Aggregator

In this case it is assumed that the BRP and the aggregator have active communication. The BRP's nomination schedule is adapted to the expected actions of the aggregator upon its portfolio. The settlement for demand response could be done, as described in chapter 2, at the 'Full MP' or at 'MP-G'.

The Aggregator Receives Full MP for Demand Response Reductions

Under the full MP proposal the BRP has balancing responsibility and covers the imbalanced position at the market marginal price. The aggregator receives the full MP for the activation of downward DR and does not have to pay the rebound price of energy at a later hour. Figure 4.16 represents the profits of the Aggregator, on the left, and the BRP on the right. The aggregator's profit is calculated according to (4.12). In this scenario G is zero, therefore the aggregator does not pay a transfer to the BRP. As c, the aggregator's cost of providing the service is assumed to be zero, the aggregator's revenue is equal to the profit. The aggregator obtains revenue from selling DR at the market price, as represented by the white bar in the figure.

In the lefthand side of figure 4.16 a breakdown of the effect of the aggregator on the BRP's profits is seen. As explained earlier, demand response has two effects on the market profits of the BRP. The first is a savings on sourced energy, since the BRP no longer has to buy that energy to cover its load. The second one is a loss at a later time when consumers rebound and make up for the earlier decrease in load. Equation(4.13) describes the BRP's profits due to demand response. In the figure, the black bar represents savings on energy sourced. The light gray bar represents the costs of covering the rebound from DR shifting at a later hour. The white bar represents the profit for the BRP, meaning the difference between the income from savings minus any rebound costs. It can be observed that the savings that the BRP obtains from avoiding energy purchases offsets the cost it has to cover for the rebound at a later hour. This is because downward demand response is activated during high price hours while the rebound occurs during low price hours. The profit observed for the BRP is, therefore, gains from arbitrage in energy sourcing costs due to the actions of the aggregator.

The Aggregator Receives MP-G for Demand Response Reduction

Figure 4.17 presents a second scenario of demand response remuneration, where the aggregator receives the marginal price minus G for downward demand response. The left part of the figure compares the aggregator's revenue for DR sales, black bars, versus the G payment it must make to the BRP for the energy. The white bar represents the revenue minus the G payment. In both of the proposed scenarios, the aggregator incurs a loss. In reality, at this point the aggregator would not participate in the market any longer. The algorithm optimizes total system costs so flexibility is dispatched as long as it is cheaper than the marginal generator. However, a profit maximizing aggregator would not be willing to participate in the market under these conditions.

The graph on the left hand side of figure 4.17 represents the income and costs breakdown for the BRP under the same scheme. The black bars again represent the savings on sourced energy. The dark gray bar is the G income, which corresponds exactly to the G payment made by the aggregator. The light gray bar represeents the cost of the rebound demand. The white bar represents the profits for the BRP. The transfer value G is set at 30 €\MWh and 45 €\MWh respectively. Now, for downward demand response, in addition to the savings in sourced energy, the BRP is also receiving a transfer payment value. However, much less demand response is dispatched in these two cases because flexibility

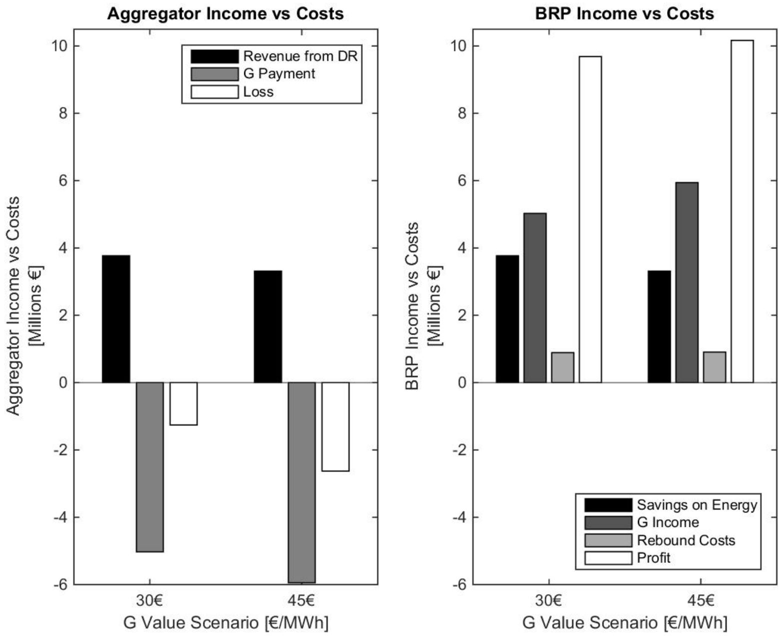

fig. 4.17. Profits for the aggregator (left) and the BRP (right) when the aggregator receives MP-G for downward demand response

is more expensive than the base generators competing in the market. Upward response occurs almost only at hours when the market price is negative due to high RES availability and low demand. Therefore the value of the rebound is also an income for the BRP in these two cases. When the aggregator also pays a transfer value to the BRP, the BRP's income increases event though the amount of demand response decreases.

The BRP Does not Observe the Actions of the Aggregator

The actions of the aggregator cause and imbalance in the BRP's position. The BRP is not aware of the actions of the aggregator, as in the previous cases. This means that the BRP procures enough energy to serve the initially forecasted load ending up with a long position when the aggregator activates a demand reduction. At a rebound moment, the BRP will not have bought enough energy to cover the expected demand plus the rebound and will have a short position.

The effects of demand response on the imbalance market are isolated in figure 4.18. These results are calculated using the imbalance prices in Belgium 2015. Demand response creates both positive and negative imbalances for the BRP, leading to a net imbalance value over the entire evaluation period, as follows:

- Positive imbalance: created when injection exceeds off-take. Demand response reduction causes a long position in the BRP's portfolio. The BRP sourced more energy than its clients actually consumed. This excess of energy is sold at the imbalance price when it is helping the system. Demand response tends to help the system, as it is likely to be activated at a time of high load, although there might be exceptions. The imbalance income for each scenario of G is represented by the black bars in figure 4.18.
- Negative imbalance: created when off-take exceeds injection. A few hours after a demand response reduction event consumers are expected to consume the energy previously reduced. This is the rebound effect that causes a short position in the BRP's portfolio. The BRP needs to buy energy to cover this short position at the imbalance price. This value is represented by the gray bars in figure 4.18.
- Net Imbalance value: over the entire evaluation period, for each value of G, the net imbalance value is the difference between the positive imbalance income and the rebound imbalance payment. This value is represented by the white bars in figure 4.18. Given the input imbalance values the net imbalance ends up being positive.

Three scenarios of transfer payment costs of the aggregator are presented. Similar to the retail effect the transfer payment is not directly added to the imbalance value. It does affect the amount of demand response dispatched and therefore it affects the final imbalance value.

The attribution of the imbalance position is under debate, but as can be concluded, under the current imbalance pricing scheme the imbalance created by demand response is actually creating profits for the party bearing the balance responsibility. There are three main positions on the attribution of this imbalance:

- The imbalance is attributed to the BRP.
- The imbalance is attributed to the Aggregator.
- The imbalance is neutralized by the system operator and its costs are socialized.

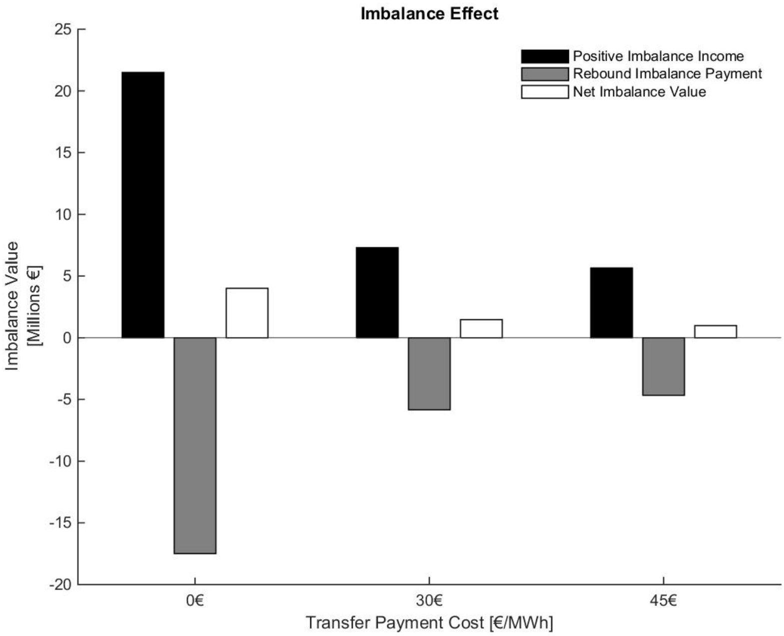

fig. 4.18. Imbalance effect of demand response if BRP position is left open

Imbalance Absorbed by the BRP

The open positions caused by the aggregator are attributed to the BRP in figure 4.19. The same three scenarios presented before are grouped in one figure: where the transfer payment is 0, 30 and 45 €\MWh respectively. In this case the transfer payment G is not directly applied, rather it affects the amount of demand response dispatched and therefore the total imbalance. The net imbalance is represented by the light gray bars in the figure. The profit is calculated by adding the BRP's income for savings on energy, G income where applicable, subtracting or adding rebound costs, and adding the net imbalance. It can be observed that as the net imbalance is positive it increases the BRP's profits.

Imbalance Absorbed by the Aggregator

In this case the open positions caused by the aggregator are attributed to the aggregator instead of the BRP. This case assumes that there is exact information about the nature of the BRP's imbalance. Other causes for imbalance, such as errors in forecasting, are clearly identified. Only the imbalance caused by

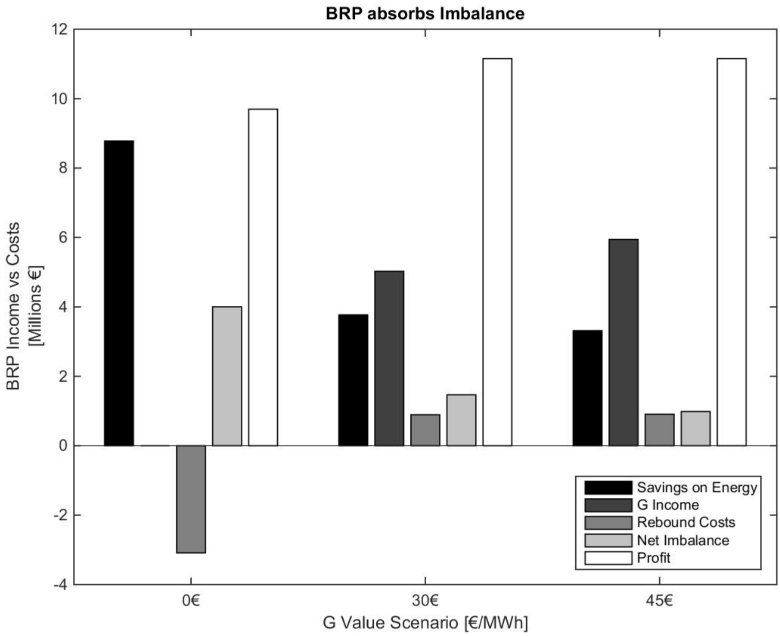

fig. 4.19. BRP's income and costs when it absorbs the net imbalance value

demand response is attributed to the aggregator. Figure 4.20 presents the income and costs that the aggregator faces, as presented earlier, plus the net imbalance. The same three scenarios examined before are grouped in one figure, the transfer payment is 0, 30 and 45 €\MWh respectively. It can be observed that the net imbalance adds to the income of the generator since it is positive. In the first case, where G is equal to 0 €\MWh, the net imbalance creates additional income for the aggregator, increasing the already existing profits by 45 %. In the second case, where the transfer payment G is equal to 30 €\MWh, the net imbalance income helps to recover part of the transfer payment G, and the aggregator earns a small profit. In the third case where the transfer payment G is equal to 45 €\MWh, the net imbalance decreases the total loss incurred by the aggregator, but the revenues remain negative.

Imbalance Absorbed by the System Operator

In this case, the open positions caused by the aggregator's demand response actions on the BRP's portfolio are absorbed, or neutralized, by the imbalance market operator. This means that the costs of sourcing the energy to cover

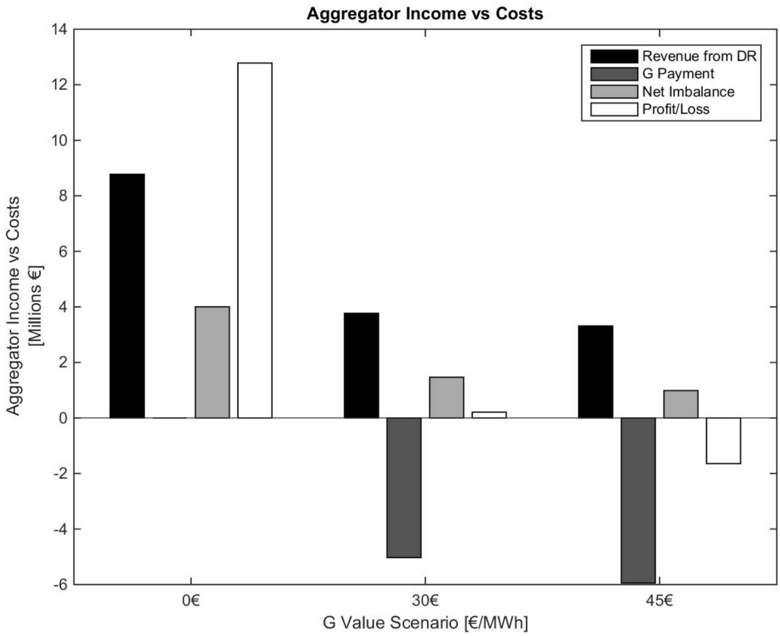

fig. 4.20. Aggregator's income and costs when it absorbs the net imbalance value

the imbalance through reserves are covered by the system operator. The cost is reflected by the first figure where the positive and negative imbalances are shown, figure 4.18. In this scenario, the net imbalance is positive, representing an income for the imbalance market operator. If it were negative, the costs would have to be allocated to consumers through tariffs.

4.4.2 Retail Effect

The retail effect of demand response was identified in section 3.2.2 of chapter 2. It is caused by the loss of profit coming from retail tariffs at the time of a demand response reduction, and an increase at the time of a demand rebound.

Figure 4.21 presents the retail effect of demand response on the retail profits of the BRP. The black bars represent the rebound income at different scenarios for the cost of the transfer payment from the aggregator. The transfer payment was added to the market effect, therefore it doesn't have a direct effect on the retail income. However, the transfer payment affects the total amount of demand response dispatched, impacting as well the retail effect for the BRP. The gray bar represents the loss of profit expected by the BRP due to the downward demand response activation. The white bar is the difference of the previous two representing the a small net retail profit for the BRP in all three cases.

In the intuitive example presented in 3.2.2 it was expected that the retail effect would be negative for the BRP. Meaning that as consumers shifted their consumption from high price hours to low peak hours, the BRP would incur a retail loss. However, in the dynamic simulation the result is different. There are two main reasons for this:

- There is a shifting horizon of 24 hours applied to demand response. Due to this, the shifting cannot always occur at the least price hours. Depending on the difference in the peak price and the low price, it can still be profitable to dispatch demand reductions even when shifting has to happen at a higher rebound price.
- The peak/ off-peak tariff regime assumed does not reflect directly the market prices. Peak hours have been assumed to range from 8 am - 7 pm, and the rest are off peak hours. While, for the market at 10 am there might be a valley, for a consumer 10 am remains a peak hour. When shifting is done by a third party aggregator who makes decisions based on the market price, and not on the tariff of the consumer, it might not reflect what is in the best interest of the final consumers.

4.4.3 Total Avoided Costs

The benefit of demand response is analyzed by running the algorithm once more without any demand response. The benefit, in this context, is the change in the objective function, equal to the actual costs of generation and demand response. Figure 4.22 represents the total system costs and zooms in on the savings achieved through demand response. The top graph represents the market costs given by the objective function (4.1). The total costs without demand response are shown for the scenario without demand response at 344.2 million €, with the introduction of 5% of peak load demand response capacity the total cost decreases to 326.13 million €, as evidenced by the first and second bars of the top graph. The third and fourth graphs represent the system costs when the aggregator must pay transfer costs of 30€\MWh and 40€\MWh respectively. Market costs, at 335 million €and 337.9 million €, are still lower than in the case without demand response but not as much as in the case where there is no transfer payment.

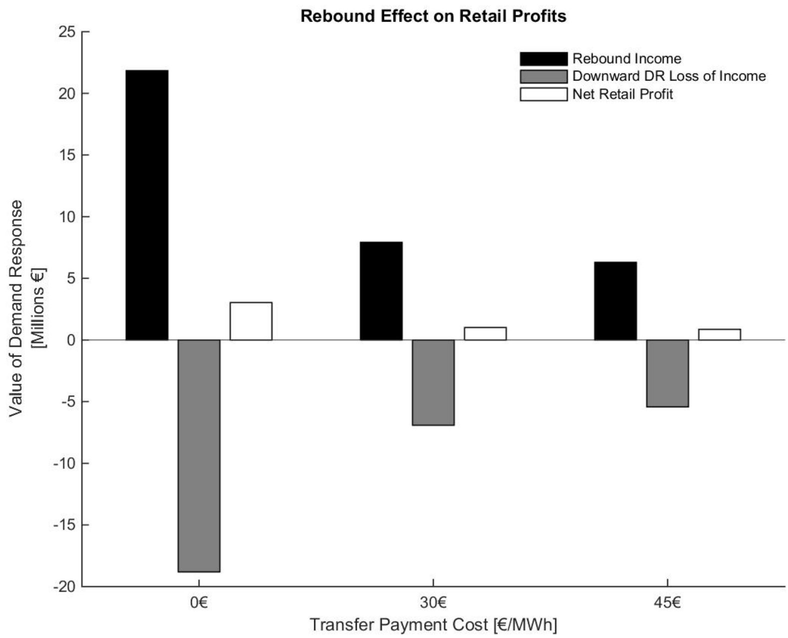

fig. 4.21. Retail effect of demand response on BRP's profits

The bottom part of figure 4.22 zooms in on the avoided costs achieved through demand response. The avoided costs are calculated as the total market cost without demand response minus the total cost in each respective scenario. It can be observed that when a transfer payment of 30 €\MWh the expected savings are decreased by more than half going from 18.1 million € to 7.9 million €. This can be observed in the first and second bars of the graph. The third bar, at 5.7 million € represents the savings achieved at a transfer cost of 45 €\MWh.

4.5 Conclusions on the Effect of Demand Response on the Wholesale Market

Demand response in the wholesale market acts as a price arbitrator creating profits for the aggregator role. As load becomes responsive to price, peaks are shaved and valleys are filled in the load curve. As RES increasingly comes in

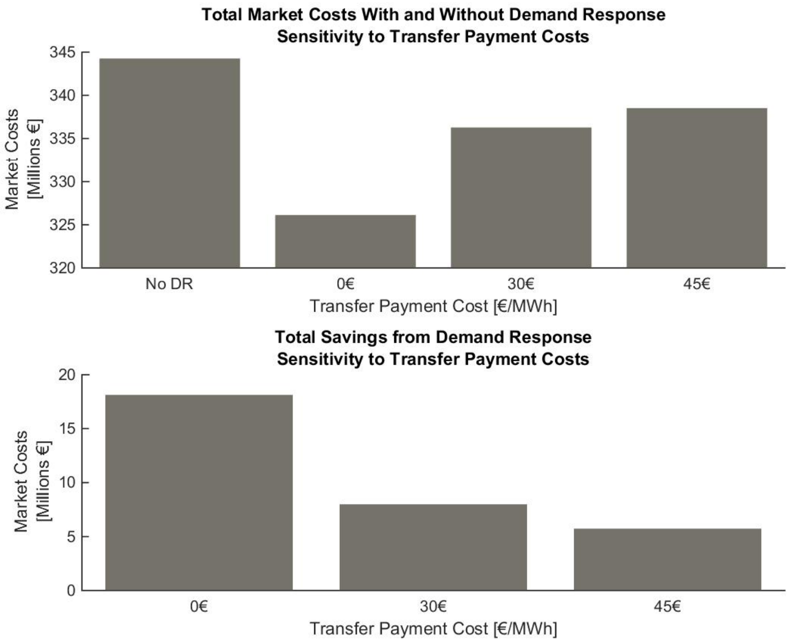

fig. 4.22. Total supply costs with and without demand response [top] and avoided costs due to demand response [bottom] under three scenarios of transfer payment costs

the market, DR use and profit value increase. This is because RES variability needs to be quickly compensated through other means.

The presence of an extra resource that eliminates the need for peaking generation also benefits BRPs who have to cover their portion of demand. DR availability means that BRPs have the opportunity to buy cheaper energy than they can generate. This is especially true for peaking generators.

For the BRP there is a certain 'windfall' profit effect on the retail profit when there are peak/off-peak tariffs, as the aggregator shifts energy consumption in favor of the BRP. The BRP procures energy less costly energy for its consumers due to the actions of the aggregator. This is because demand is shifted from expensive peaking hours to valley hours.

It was shown that demand response reduces total costs of operation. A case where the market is run with and without demand response is shown. In the presence of a transfer payment at 30 €\MWh total avoided costs decrease by

50%. The transfer payment also reduces the total amount of demand response present in the market. In the model, the aggregator would not have a positive business case if transfer payments are introduced given the input market prices. Introducing a transfer payment hinders active participation in the market by consumers.

Part II

Chapter 5

Local Flexibility Markets

This chapter is partially based on: [106]

Ramos Gutierrez, A.; De Jonghe, C.; Belmans, R., 'Realizing the Smart Grid's Potential: Defining Local Markets for Flexibility', Utilities Policy, volume 40, June 2016, pages 26-35, ISSN 0957-1787

During the late 1990s and early 2000s it became apparent that the increase in local DER needed to be managed in a different way than conventional power plants (CPPs). The latter were already known to the system operator in terms of connection, power output characteristics, and grid service possibilities. In contrast, system operators lacked a view on the availability and functioning characteristics of small DER connected to the distribution grids. The concepts of microgrids and virtual power plants started emerging in literature as a way to group the characteristics of DERs. The purpose was to offer a unified profile to a system operator in order to enable better grid control, additional reserves, and eventually market participation for small generators. Over the years it became evident that more than a single characterization of profiles was needed. Enabling these new roles, needed by the system operator, made small generators enter into contracts with intermediaries instead of big suppliers. Soon it became apparent that there was an economic value in the offer of aggregated DERs, and not only system operators could take advantage of it. Commercial actors such as retailers and balancing responsible parties could also use the flexibility that became available. It became apparent over the years that there is a need for structures and markets to allow the interaction between the involved buyers and sellers of location specific flexibility.

There are different views on what shape the local market for flexibility should

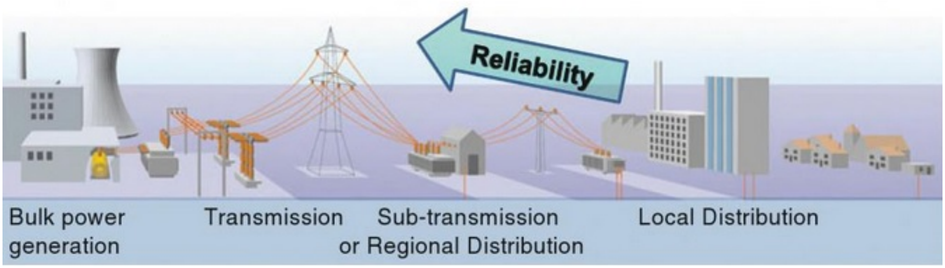

fig. 5.1. Power system description.

take. The current discussion in literature has yet to formally define what a local market is, what is expected from it and what the market design should be based on such expectations. In order to arrive at a definition and purpose of a local market first the concept of locality is examined. A generalization of the definition of locality is presented in section 5.1. The need for a local market is described in section 5.2. Section 5.3 presents the evolution in literature of the concept of a local market. Based on the literature a definition and purpose for a local market are abstracted in section 5.3.3. The variants of current local market design proposals are evidenced in section 5.4. Main trends in local market design are abstracted in section 5.5. Flexibility as a reserve contracted by either the DSO or the TSO is proposed in section 5.6. Local competition for flexibility is proposed in section 5.7. Chapter conclusions are presented in 5.8.

5.1 Definition of Locality

Locality is described by three main characteristics influencing the decision making process of a stakeholder:

- Geographic area: political borders affect the regulation in place for a specific resource. Regulation can affect the willingness of consumers to install renewable energy systems, batteries, or home efficiency systems. Similarly, regulation affects the tariff schemes that consumers are exposed to in terms of grid-use as well as taxes and levies.
- Network operator: Depending on voltage level and geographic area a TSO or a DSO might be the manager of a specific resource. In certain countries there is only one TSO (eg. Spain, France, Belgium, Italy); while in others there is more than one (eg. Germany). Depending on the jusrisdiction of a system operator and the regulation in place, connection procedures and

possibilities to sell system services on an aggregated level may vary. The number of DSOs in a country also varies widely, from one or two main DSOs to even hundreds of small ones defined per locality in certain cases. Portugal for example has thirteen DSOs, out of which only three manage more than 100,000 consumers. Germany on the other hand has more than 800 DSOs out of which 75 manage more than 100,000 consumers [107]. Given that DSOs and TSOs might purchase and use flexibility resources, the network operator that a customer is connected to makes a difference.

- Network connection: users can be connected to either high, medium or low voltage (HV, MV, LV respectively). From a topological perspective, users located in rural areas, might face a lower power quality. The transmission and distribution networks are described in figure 5.1 [108]:
  - The transmission network transports energy to the sub-transmission or distribution networks.
  - The medium voltage network accommodates medium power plants from tens of kW to 10-20 MW.
  - The local distribution network supplies households, small businesses, buildings and small power producers.

Conventional power plants and large industrial consumers are connected to the high voltage network, and directly visible by the Transmission System Operator (TSO). The TSO manages the HV network and depending on the jurisdiction the TSO also manages part of the MV network down to 66 or even 36 kV. As the entity in charge of maintaining system balance, the TSO usually has good visibility and measuring capabilities of the transmission lines and substations connected to its network.

The Distribution System Operator (DSO) is in charge of the low voltage network. DSOs evaluate connection requests, from consumers and small producers, using worst case scenarios. If the connection capacity is deemed adequate, the requester is granted permission to connect to the network. Otherwise reinforcements need to be made before the connection can take place. This means that network capacity can be over-dimensioned as a worst-case-scenario is only likely to take place during a few hours a year, if at all. DSOs have very low visibility over the resources in the distribution network. Thus, the introduction of DERs causes a stir in network management as variable generation in the distribution network grows and users gain capabilities to respond to prices. In addition, traditional consumers can also generate electricity therefore becoming 'prosumers'.

The concept of locality is depicted in fig. 5.2. A producer or consumer can belong to a certain geographic area, a specific DSO and a voltage level. Therefore,

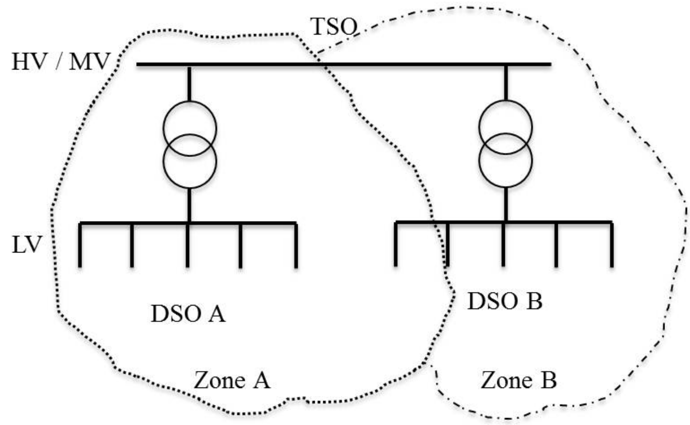

fig. 5.2. Visualization of geographic and voltage aspects of locality

contracting local resources is a complex task that requires coordination among different actors in order to take into account physical, contractual, managerial and regulatory aspects.

Smart contracts are proposed in [109] and defined as customer-specific contracts that reflect the situation of the network and use the specific characteristics of customers. Contracts that emerge naturally from the market could provide enough flexibility to more efficiently plan network investments in the distribution grid.

5.2 The Need for a Local Market

Given the complexities of flexibility outlined above, the specifications of locality, and the diverse nature of the stakeholders involved in the flexibility value chain it is advisable to set up structures that allow the use of flexibility resources in an optimal way. This view is supported by literature but opinions vary on what the best way is to set up these structures.

In [110] it is stated that the Guideline on System Operation and the Network Code on Emergency and Restoration place DSOs and TSOs as enablers of demand response for system reserves. Congestion management and voltage control are needed by both TSOs and DSOs. The location of resources in this case is important in order to solve a specific congestion problem.

In [111] the need for aggregation of local energy resources is encouraged in order to reduce the risk faced by market participants, decrease costs and increase the possibility of participating in the markets for system services. The authors recognize the need for a market that allows local balancing actions to take place at the DSO level. The need for regulation that encourages DSOs to start new marketplaces to procure system services is examined in [112].

In a position paper, EURELECTRIC claims that the aggregated flexibility services required for constraint management and balancing could be delivered by the same resources [4]. In addition, they state that a common place to pool flexibility should be explored as an option for coordinating actions.

According to EDSO network operators will have to balance supply and demand, exploiting market mechanisms in the reserve market (e.g., existing mechanisms in some countries like automatic and manual frequency restoration reserves as well as to-be-designed mechanisms like ancillary services markets) [113]. Depending on different network conditions, such active management and dispatching functionality will be implemented directly by the TSO, in cooperation between TSO and DSO, or by the DSO itself.

CEDEC states that there is a need for clear rules to purchase system services at distribution level while avoiding inherent conflicts with other market actors such as aggregators [114]. Under the current set up these local aggregators provide balancing services to either the TSO or the wholesale intra-day markets.

In the United States, the U.S. Department of Energy Efficiency and Renewable Energy (EERE), states that the system must have sufficient capability in flexible generation or demand response to make up variable generation [115]. At the same time, they indicate that the institutional framework, including market and operational practices, must allow access to physical flexibility.

It is still unclear which market role should be expected to initiate the development of decentralized flexibility resources [116]. Aggregation is proposed as a choice that should be born out of economic motivations, and not due to market regulation requirements. The author recommends that in order to avoid the risk of new barriers and additional transaction costs initially existing roles should handle the aggregation task for demand flexibility. The authors propose that the flexibility aggregation role should be integrated in the retailer activities in order to avoid settlement issues with the BRP.

In [20] it is argued that DG could positively contribute to the operation of networks. DSOs could make an optimal choice between reinforcing the network and implementing active network management. It should be compensated through commercial agreements such as bilateral contracts, regulated payments, acknowledgment in use of service charges, or network related markets.

Decentralized resources are valuable to the system. Mechanisms that allow actors to interact and trade these resources could enable their integration in a sustainable way. Although the need for a local market has been identified, opinions in literature and ongoing projects vary as to what the is best way to set up a local market.

5.3 Definition of a local market

As has been described above, there is a need for an institutional framework that allows the purchase of flexibility at a distribution system level. Since the distribution grid is local, contracting flexibility services in this context can be referred to as a 'local market'. In order to arrive at a complete definition of local market it is necessary to take a step back and see the evolution of concepts in local flexibility management and contracting.

Management of DER was first proposed in literature through the concepts of microgrids and virtual power plants. Both are closely related, the main difference is that in a microgrid the value is determined from an internal optimization while in a virtual power plant it is given by sales volume coming from external processes [117]. Their first applications were directed towards technical grid management: voltage and reactive power control. Once the economic value of the resources became evident, it was clear that structures that support trading commodities were necessary. The evolution of microgrids is explored in subsection 5.3.1, virtual power plants in subsection 5.3.2, and the extension towards local market proposals that followed in subsection 5.3.3. Finally the complete definition of a 'local market' is presented in subsection 5.3.3.

5.3.1 Microgrids

A microgrid is defined as a cluster of DR units and loads, serviced by a distribution system, that can operate in the grid-connected mode, the islanded (autonomous) mode, and ride-through between both modes [118]. It is assumed that multiple generators and aggregated loads are reliable and economically sound as an operational electric system. In a similar approach [119] also studies microgrid voltage control through peer-to-peer communication between system components. The concept of microgrid control is studied from a multi-agent system perspective [120]. Several other studies have been done on the autonomous operation and voltage/var control of microgrids [121], [122]. In [123] a review of the trends in microgrid control is presented. The main control principles studied are droop control, model predictive control, and multi-agent systems. The concept of microgrid is extended toward the multi-microgird when most of the low voltage networks turn into active microgrids [124].

From a commercial point of view microgrids are studied as a problem of demand allocation of available RES to either one or several utilities representing demand [125]. Utilities have a regulatory commitment to supply a certain part of demand from RES. It is shown through a multiple utility market model that the allocation to one single utility is more profitable. Commercializing microgrid services gave rise to the concept of virtual power plants.

5.3.2 Virtual Power Plants

A virtual power plant is defined as a cluster of dispersed generator units, controllable loads and storage systems, aggregated in order to operate as a unique power plant [126]. An energy management system coordinates power flows at the point of common coupling of generators, controllable loads and storage. In another view, a virtual power plant is defined as an information and communication system that aggregates controllable distributed energy units or active customer networks by direct centralised control [127].

A distinction is made in the literature between technical virtual power plants (tVPP) and commercial virtual power plants (cVPP) [128], [129]. The concept of aggregating location specific resources is introduced in the tVPP. It is formed by groups of controllable DERs in the same geographic location, and is pertinent to local grid management. A cVPP, in contrast, is not necessarily geographically constrained, it may contain resources from different geographical areas, aggregated into supply curves that can participate in a market.

It is recognized that through the VPP concept individual DER are able to gain access and visibility across all energy markets and system operation will benefit from optimal use of all available capacity and increased efficiency of operation [129]. Therefore a VPP is a flexible representation of a portfolio of DER.

A review of VPP literature expands the definition of VPP to: a portfolio of DERs, which are connected by a control system based on information and communication technology (ICT). The VPP acts as a single visible entity in the power system, it is always grid-tied, and can be either static or dynamic [130].

5.3.3 Local Market Definition

In general terms, a market can be roughly defined as an environment that allows potential buyers, sellers, and retailers of a given economic product to engage in trade [35]. The definition of market entails two principles, the entire market and its composing sub-markets [37]. An entire market typically consists of a set of closely related end-products and the intermediate-product markets that feed into them; the sub-markets of an electricity market include the wholesale spot market, wholesale forward markets, and markets for ancillary services. Besides the obvious need to agree on the quality, quantity and price of the goods, three other important matters must be decided when a buyer and a seller arrange a trade: date of delivery of the goods, mode of settlement, and transaction conditions [35]. A local market is defined by its spatial specifications and can be thought of as a new sub-market for flexibility.

ENTSO-E defines a 'local market area' as a type of market area where there are no transmission capacity restrictions between the market balance areas. A market area is defined as an area made up of several Market Balance Areas interconnected through AC or DC links. Trade is allowed between different market balance areas with common market rules for trading across the interconnection [131]. ENTSO-E is concerned with large areas of trading, the local needs of DSOs are not taken into account in this definition.

A local electricity market is defined as a geographic area where consumption and generation can be metered, there are no transmission capacity restrictions and for which there is one BRP, and thus, one price for the imbalance [132]. The goals of this market are voltage support, frequency control and provision of reserve active power as an ancillary service. The authors seek to use a local market to trade electricity among the participants in the distribution network in order to achieve market efficiency. The restriction of the market to one BRP is a defining characteristic of this definition. If only one party has balancing responsibility, the issue of determining the source of imbalances is skipped.

Market-based control is defined as the implementation of price-signals by the macroplayers in order to optimize global system performance through the coordination of the resources of the microplayers towards predefined network and market goals [133]. A distinction is made between macro and microplayers. Macroplayers are decision makers such as regulators, retailers, DSOs and TSOs. They provide price signals and technical constraints to the microplayers. Microplayers are prosumers who act on the distribution grid. An auction design for local reserve energy markets is proposed in [134]. The local market is designed for private households, and limited to a single balance group.

Definition

Joining together elements from the definition of a market, aspects of locality and proposed literature, the following definition of local markets takes shape:

Local Market: Long- or short- term trading actions for flexibility in a specific geographical location, voltage level, and system operator (DSO and TSO), given by grid conditions or balancing needs, where participants in a relevant market can be aggregated to provide flexibility services.

Purpose

The purpose of a local market can be abstracted from the purpose of using flexibility [4]: system balancing, constraints management, and portfolio optimization.

The distinctive component is that resources are differentiated by location and the DSO is directly involved. Thus, it can be said that the purposes of flexibility can be transferred to a local market:

- Balancing a locality to match demand to the varying renewable supply in case of congestion.
- Constraints management in transmission and distribution networks.
- Portfolio optimization for market agents, taking into account network needs at specific times and places in the grid.
- Grid investment deferral if flexibility can be effectively used as part of the grid planning of a DSO.

Flexibility for the purpose of system balancing is contracted by the system operator. Balancing refers to the procurement of balancing services (capacity) and activation of balancing energy by the TSO to balance demand and supply through the balancing market [4]. Balancing the system has been a traditional role of the TSO. Conflicts can arise when resources participating in balancing actions are connected to the distribution network. The TSO does not have a complete view on the state of the network of the DSO, nor on the access contracts of the parties connected to it. Communication between the DSO and TSO can be done ex-ante or close to real time for balancing purposes. In an ex-ante scheme the DSO performs preventive worst case checks before a customer connected to its network can offer services to the TSO. The downside being that flexibility is limited to a worst case scenario not very likely to occur.

It leads to a loss of potential flexibility for the system. On a real-time basis, the DSO would have the faculty to approve or deny a flexibility transaction based on the state of the network. Although more accurate, this method requires investments in advanced measurement and communication systems. Given the high amount of components in the distribution system, this investment might not be feasible at every location. Communication between system operators is essential to outline rights and responsibilities of all the actors involved in maintaining system balance.

Flexibility used for constraints management can be activated on the generation side, on the demand side, or through system reconfiguration directly by the DSO. Beyond corrective actions that the DSO can take in its own network, such as system reconfigurations, there must be a fair way in which flexibility can be contracted. On the generation side it refers to re-dispatching of units in order to comply with the thermal limits of the lines and equipment in the distribution network. On the demand side it refers to requesting demand to adapt its consumption up or downward at a given moment depending on network conditions.

Portfolio optimization refers to commercial actions of market participants in order to decrease their costs of imbalances and hedge risk. The day-ahead and real-time needs of a market player depend on its remaining open positions as given by long term contracts. They need to cover a long or a short position through selling and buying in the short term markets. These differences between the long term contract and the real time demand can be due to errors in forecasting, unscheduled plant maintenance, or plant failures. Market actors have traditionally hedged through contracts mainly with supply side flexibility. Demand side flexibility, contracted directly with large consumers or through aggregators, is a new tool that they can use to improve their real time positions. The market design must allow such transactions to take place fairly and transparently.

Grid investment deferral can be achieved through the use of flexibility when the extra capacity is only needed for a few hours a year. If the DSO actively contracts flexibility as part of grid planning activities, it can be said that investment deferral is a purpose of using local contracting. Flexibility contracts would also need to be mid- to long-term to ensure that flexibility is available when needed. The cost of investment in new lines marks the cap of the cost for flexibility. If flexibility is more expensive than the cost of grid expansion, it is simply better to invest in grid expansion than to contract flexibility.

5.4 Current Local Market Design Proposals

Local market design proposals in literature vary in shape and form. They range from a centrally coordinated approach to a completely decentralized system with many decision makers. In the paragraphs that follow, the main approaches in literature and ongoing research projects will be presented.

It is argued that electricity systems are now experiencing a transition from a 'top-down' toward a 'distributed local' system [135]. The authors raise the open question about whether a fragmentation of the internal EU market at national and sub-national levels is desirable.

Different approaches of handling congestion in the distribution grid from a market perspective are defined in [136]. The first is an integrated approach as a stepwise process that finds first the system balance and then solves congestion, and the second is a process that solves congestion and then finds system balance. The author proposes that congestion can be solved as either a sub-market of the wholesale electricity market, a spatial market defined by geographic location, or a hierarchical market aligned with grid topology. A sub-market of the wholesale market trade is made through the existing platforms with the addition of a locational component to the usual price-quantity bids and offers. A spatial market is separate from the existing wholesale market created for a specific location. Finally, a hierarchical market is a restriction made to trade all resources first locally on a geographical market; in the absence of congestion they can be made available to the wider wholesale markets.

A system with locational granularity is supported by [137] due to the fact that the best locations for wind farms are located far from load centers. It is impossible to clearly define zones that would reflect physical realities at all times. The above mentioned authors believe that nodal pricing at transmission level is recommended as the best option to reflect the variability of flows. Furthermore, price boundaries reflect the value of flexibility and negative prices should be implemented.

Locational prices are simulated on a test network to promote loss and line loading reductions [138]. The authors propose that it makes sense to consider nodal pricing in distribution. A similar study is carried out by [139] in a distribution test network in order to optimally locate DG resources. These studies, however, propose an optimal analysis of the networks and do not take into account the complexities of a market design that would allow the achievement of the optimal network.

Under an integrated approach the network is taken into account during the market clearing process. As a part of the wholesale market, the issue has been studied and implemented mainly in the United States, the market then becomes a nodal market. Participants submit bids consisting of place, quantity and price. A centralized market platform calculates the balance of supply and demand alongside the state of the grid. The resulting nodal price consists of three components: energy, congestion and losses. This approach, however, has been criticized for lack of transparency, as specific prices are often hard to explain. It has only been applied at a transmission level. Cascading a nodal price approach to the distribution level poses computational challenges, and would lead to even more transparency issues.

In a market based approach the literature suggests the use of distribution locational marginal prices (D-LMP) that signal to users when it is optimal to consume and or produce. Congestion management in a distribution grid via shadow prices is proposed in [140].

The complexity of distributed energy resources is modelled in an iterative architecture that sets transmission and distribution locational marginal prices [141]. An optimal scheduling of centralized and decentralized generation, flexible loads and distributed energy resources is proposed. Resources in distribution are used to manage congestion at the transmission distribution interface. The algorithm is solved for 24 hours successfully, the development of real size software implementations is cited as future work.

A distribution locational marginal pricing method is proposed to alleviate congestion through the use of flexible demand [142]. The authors assume that the DSO calculates the dynamic tariffs and publishes them to aggregators who make optimal plans for flexible demand.

Nodal pricing for distribution networks are shown to show significant price differences between buses reflecting high marginal losses, and resources located at the end of a network are more valuable [143]. The paper assumes that there is no congestion on the distribution network and takes losses into account. A modification of marginal prices at the transmission interface using marginal loss coefficients arrives at locational marginal prices in distribution in [139]. A distribution locational marginal price is calculated and used by individual loads and generators to submit bids and offers that are checked against an optimal power flow [144]. Another optimal power flow approach to locational pricing in distribution to manage congestion is proposed in [145]. Other methods to calculate the locational marginal price in distribution are proposed in [146], [147], and [148].

The main variants observed refer to whether the network is taken into account or not. The second attribute is whether the distribution network is taken into account or only the transmission network. Most designs proposed so far, fail to take into account the interests of the involved stakeholders. They refer mostly to spatial aspects of trading, while neglecting the contractual, time frame and price-clearing aspects of market design. Over the past years there have been a number of research and demonstration projects related to contracting local flexibility. A few of the most relevant projects are described in the sections that follow.

5.4.1 Project Fenix

The project proposes the management of Distributed Energy Resources through a virtual power plant that aggregates units into a portfolio [149] [128]. The provision of ancillary services by DERs is explored technically, and economic trading commercially. Among the systems analyzed are:

- Wind turbines.
- Photovoltaic systems.
- Hydroelectric power stations.
- Cooling and heating systems.
- Storage systems.

Through the virtual power plant proposed in FENIX individual DERs can gain access and visibility across energy markets, and benefit from VPP market intelligence to optimize their position and maximize revenue opportunities. The VPP also gives visibility of available resources to the system operator. A distinction is made between technical and commercial VPP (TVPP, and CVPP). A TVPP takes into account network characteristics where a specific DER is located, while a CVPP only considers economic characteristics.

The TVPP groups resources from the same geographic location. An aggregated profile includes the influence of the local network on the portfolio output and also represents the DER costs and characteristics. The operator of a TVPP requires technical information. FENIX states that typically this should be the DSO due to the network visibility required to run a TVPP. The aggregation of resources also allows generation and demand to contribute to transmission system management. At the distribution-transmission network interfaces the TVPP presents a single profile representing the whole local network. Information of each DER is submitted to the TVPP by the CVPP over the resources located in the area covered by the TVPP. The project quantifies benefits of using a CVPP in terms of the costs and benefits of the DG resource, the CVPP, the suplier and a central producer. This arrives at a quantification of the system net benefits in € /kWh/year.

Benefits for the TVPP are not quantified in the project as they are deemed to be too variable depending on the grid characteristics. A qualitative analysis estimates that TVPP operations can reduce network costs through the reduction of energy losses, deferral of network investments, reduction of penalties for both non-supplied energy and quality of service; and enlarged scope of options for distribution and transmission services.

The project proposes regulatory recommendations in terms of incentivizing DSOs towards a more active system management. Metering and communication, network and market access for DER resources are stressed. DER should have access to ancillary services and technology support to encourage the use of flexibility.

The economic exchanges as well as roles and responsibilities of each actor in the Fenix model are outlined in [150]. While the project is not specific on contract criteria, it proposes marginal bid prices for DER operators and large power producers offering balancing services. It sets the TSO as the single buyer paying this marginal bid price. In other cases it leaves the scenario open to specific country regulation on remuneration for system services.

5.4.2 ADDRESS

The ADDRESS project aimed to integrate active demand in the form of domestic and small conmmercial consumers in the electricity markets and in the provision of services to other electricity system participants [151].

In the project, three levels of DSO control are taken into account [152]:

- The DSO central control level for network operation and active demand (AD) management.
- HV/MV substation level to enhance MV network monitoring and to enable strategies for voltage regulation and power flow control.
- The MV/LV substation level to enable functionalities needed for LV network monitoring.

To allow the inclusion of active demand, the DSO needs to do an ex-ante verification of the technical feasibility of the service. This information needs to be transmitted to the TSO.

An active demand management system (ADMS) publishes a flexibility table to inform aggregators about the allowed active demand flexibility in the network. The system receives bids from aggregators, arranges the requests according to load area information, and then calls validation tools to check the feasibility of the AD products. Both ex-ante and real-time validation of offers is carried out by the DSO.

ADDRESS develops functionalities to enable the DSO to interface with the TSO in order to ensure a coordinated validation process, load area and flexibility table publication, and active demand validation management. The DSO should only keep close control of nodes and lines that could suffer insecure operation. The identification of these areas has been managed in the ADDRESS project through a distribution system model based on Load Areas (LAs).

Three main services for regulated players are envisioned:

- Voltage regulation and load flow control;
- Tertiary reserve power;
- Smart load reduction instead of blind load shedding.

For deregulated players the main services are:

- Optimization of energy purchase/sale;
- Minimization of unbalance costs;
- Optimization of investment scheduling for energy generation;
- Reserve capacity for risk reduction in terms of costs and volume;
- Tertiary reserve for fulfilling the obligations related to the requirements of the TSO.

In terms of market design, a local bilateral market is proposed for local markets at distribution level [153], because of their limited size. If liquidity increases, calls for tenders may be possible. Flexibility markets could pool flexibility capacities in order to make offers in other markets, only necessary if the individual actors cannot participate directly in the other markets. This flexibility market can be organized as bilateral contracts or as an organized platform. A Conditional Re-Profiling Products (CRP) market is also proposed through the exchange of standardized volumes, but it is not recommended due to possible liquidity limitations. A possible local market could be set up using a market splitting mechanism method from the TSO level market when there are congestions. In terms of technical validation of flexibility resources, it is proposed that the DSO should be allowed to curtail the local resources without taking into account economic data, which puts the cost of operation on the resource operators. Alternatively, in a market based approach the DSO would be responsible for re-dispatching curtailed services and bear the costs of the re-dispatch.

Actors who could participate in a local market are identified as:

- The DSO managing a local area;
- DSO managing a neighbouring area;
- Local controllable DG owner, in order to improve his income;
- Local uncontrollable DG, in order to avoid operational limitations due to local constraints;
- Aggregators could buy to provide services locally or to the rest of the grid.

In terms of the balancing responsibility of the active demand, the report states that an aggregator should be a BRP himself, or should pass this responsibility to another party by having a contractual agreement on the costs of this responsibility. The project bypasses the baseline establishment by comparing the price/volume signal sent by the aggregator to the initial forecast or program set by the BRP; no baseline of metered consumer behaviour is established. This might be ambiguous as deviations from the profile could be caused by reasons other than actions of the aggregator. Therefore, the project states that this problem can be avoided if the aggregator is also the consumer's retailer.

Three possible solutions are proposed:

- Deviations are settled by the BRP;
- Deviations are settled by the aggregator;
- Shared responsibility of sharing between aggregator and BRP.

In terms of technical validation of active demand by the DSO, ADDRESS proposes evaluation of services on a first come first serve basis. If AD requests arrive together, the project proposes equal percentual curtailment, without the need to receive information on the price of services. The DSO does not compensate the aggregator nor the curtailment of resources.

5.4.3 EcoGrid

The purpose of EcoGrid is to develop and demonstrate a generalized real-time market concept for smart electricity distribution networks with high penetration of renewable resources and consumer participation [154].

The project proposes a bidless market where small-scale DERs and small end-consumers can actively participate in a real-time electricity market by responding to 5-min price signals [155]. A real-time price is set depending on the system operation status and needs for balancing or congestion in the transmission/distribution systems. Automatic controllers make optimal solutions at consumer premises every 5 minutes in response to the price signal. The EcoGrid real-time market complements the existing Regulating Power (RP) market. The RP market provides up and down regulation necessary for the TSOs in the Nordic countries for maintaining system balance. The new proposed market complements the RP market by aggregating response from numerous DERs and flexible demand. The real-time signal is sent directly by the TSO to the market participants. The real-time price signals should be closely coordinated with the activated bids in the RP market. In order to prevent arbitrage, participants can only act in one of the markets, perhaps reserving the RP market only for large consumers.

In order to make a decision the TSO as the sole-buyer in this market, needs information about cleared market quantities in the spot market, up and down regulation bids and prices, technical constraints of generation units, power production of RES, and aggregated response of prosumers to the real-time price signal. With this information the TSO decides: first the deployment of up and down regulating power, and second the real-time price and forecast to be sent to market players.

5.4.4 EvolvDSO

EvolvDSO proposes a new role for DSOs as a 'distribution constraints market officer' [156] [157] [158]. The DSO uses flexibility for the following purposes [159]:

- Enhance hosting capacity of the distribution grid;
- Solve congestion to maintain normal operation and respect security constraints;
- Optimize network planning;
- Maintain voltage levels.

The DSO would have the capability to contract and activate flexibility on different time frames. The project proposes the need to contract flexibility in the long term to achieve grid reinforcement deferral, non-firm grid connection and access contracts allowing temporary limitations on feed-in or power consumption, and real time flexibility contracting for operational management. Tendering is recommended for the long-term procurement of flexibility. Participation in a flexibility market alongside with other market participants is proposed to cover short term flexibility needs.

An expansion of an existing role as 'neutral market facilitator' is also proposed [159]. This role supports market participation of resources connected to the distribution grid by issuing signals to participants of the status of the grid. These signals take the form of traffic lights as a mechanism for information exchange with market participants. Three network states would be communicated: green for normal network conditions, yellow for limiting certain consumer behavior, and a red light where the DSO would take control of market actions. Under this scope the DSO should be involved in pre-qualification, validation of bid activation and settlement procedures of market operations.

The operational market would need to have strong coordination with the TSO and other existing markets. In terms of communication with TSOs the report stresses the need for exchange of structural and operational information. DSOs will need to manage TSO requests at different timeframes including network development, forecasting, operational planning and real-time operations. It is also estimated that the DSO can provide regulated services to the TSO through a cascading communication process. In [159] it is recommended to establish a hierarchy between TSOs and DSOs regarding flexibility contracting, as well as cascading processes for system support and operation.

5.4.5 Bid-ladder

The Bid Ladder, a project proposed by the Belgian TSO, is a platform where market players can bid their available flexibility. It allows bids from load and RES flexibility, as well as resources connected to the distribution grid. The platform would be oriented towards manual frequency restoration reserves. Within the manual frequency restoration reserves the TSO defines two categories: pre-contracted reserves or ancillary services that receive a capacity payment, and non-contracted reserves or bids. The latter are the focus of the bid ladder, reserves that don't receive a capacity fee and only the residual remaining flexibility is offered in the balancing market and remunerated when activated.

- Products: Three types of balancing energy products are allowed in the bid ladder platform:
  - A fast standard product: has a 15' duration of delivery time and is activated at the moment of request without delay.
  - Slow standard product: has different activation duration of delivery times -15', 30', 45' minutes- and a 15' minute activation delay.
  - Emergency products: the remaining flexibility of power units with installed capacity above 75 MW is offered to Elia. This flexibility is to be used in case where reserves cannot be offered through the standard products and under exceptional circumstances.
- Remuneration:
  - Activation fee: in case of a positive price the provider receives money for an upwards activation and pays money for a downwards activation, and vice-versa for a negative price.
  - Prolongation fee: when the TSO requests the activation of a bid that was already activated in the current time frame, a prolongation price can be paid.
- Congestion management: locational information of each resource must be provided for units larger than 25 MW in the first stage of the project. In case of smaller units, the required information needs to be discussed with the DSO.
- Flexibility type: a bid for flexibility can be provided by generation, load or both.
- Technical pre-qualification: units above 25 MW are pre-qualified individually, while smaller units may be aggregated. In order to qualify, bids should be based on physical regulation, the requested delivery should be maintained at a stable power level. Once the delivery of the bid is finished the physical regulation used should be able to go back to its normal level within 15'.

The bid ladder is a TSO-led model where the TSO takes the decision of what flexibility is contracted. The DSO has the role of pre-qualifying resources through a worst case scenario check, but is not active during operation and does not decide what flexibility resources could or should be deployed.

5.4.6 I-power/Flech

The FLECH market is a flexibility clearing house proposed to accommodate small scale distributed resources [160] [161]. Its purpose is congestion management in the distribution grid via feeder overload and feeder voltage management. Two main setups are proposed.

- Single-side aggregator auctions where the DSO proposes a request for flexibility and aggregators submit orders to satisfy the DSO needs. In this setup the DSO decides whether it is best to buy flexibility services or invest in new grid reinforcements.
- Super market: the aggregators have the initiative, they propose various services and the DSO as a buyer chooses according to its needs. The aggregator optimizes a portfolio of flexibility resources seeking to maximize its benefits.

- Products for load management:
  - Planned powercut: based on forecast of available network capacity.
  - Urgent powercut: based on events instead of forecasting.
  - Power reserve: through this product DSOs can allow the loading of feeders to exceed beyond 70% capacity limit but still below 100% capacity limit.
  - Powercap: ensure that a capacity limit specified by the DSO is not violated.
  - Powermax: similar to powercap, but it ensures that the aggregator's local portfolio does not exceed a certain amount of power during the activation periods.
- Products for voltage management:
  - Voltage Support: the DSO sends a signal to the aggregator specifying the current voltage deviation in the network. The aggregator modifies settings of the load to comply with the DSO's requirement.
  - Var Support: distributed generation units with the capability to modify their reactive power output can offer Var support to the DSO.
- Pricing: depending on the type of product, the pricing can have either of an availability payment, an energy activation payment or both. Penalties also apply in case of defaults.

- Congestion Management: products are requested for specific geographic areas and connection points according to specifications of the DSO.
- Flexibility type: both load and distributed generation qualify. Load must participate through an aggregator.

The FLECH market is a DSO-led market that serves to optimally operate the distribution grid and enable the integration of DRES. The effect of the DSO actions on the TSO network is not directly taken into account.

5.4.7 USEF

USEF proposes a market design for trading flexible energy use [162]. It is designed to fit on top of most existing energy market models.

Six flexibility services for the DSO are proposed: congestion management to avoid/delay grid reinforcement, voltage control, grid capacity management (to reduce grid losses and optimize grid use), controlled islanding, redundancy (N-1) support, power quality support.

The aggregator offers four main services for the BRP: day-ahead optimization to shift loads from a high-price time interval to a low-price time interval, intraday optimization after the closing of the day ahead market, self or passive balancing of the BRP, and generation optimization. In passive balancing the BRP is remunerated by the TSO when its deviation supports the reduction of the overall system imbalance. In this scheme the BRP uses its available flexibility to balance its own portfolio instead of bidding in the market. Generation optimization means optimizing the behavior of central production units to reduce costs and avoid imbalance.

A distinguishing factor of this model is that the aggregator only offers services to the TSO through the BRP, and not directly. Services for the DSO, and for BRPs, in contrast, are offered directly by the aggregator role.

In terms of the market design, USEF, recognizes four different operation regimes depending on the availability of reserves in the system.

- Normal operation: refers to operation without grid limitations, it is an optimization on commodity value and active grid monitoring by the DSO.
- Capacity management peak load reduction and power balancing: the DSO is active on the flexibility market, and reduces peak loads on congestion points in the grid by activating flexibility at both demand and supply sides.

- Graceful degradation, load shedding: the DSO makes autonomous decisions to lower loads and generation in the grid by limiting connections when market-based coordination mechanisms cannot resolve congestion.

- Power outage grid protection: primary grid protection systems are activated (fuses, switches) to prevent damage to assets.

The recommended pricing model is 'pay-as-bid', where all suppliers of flexibility receive the price included in their individual bids when called to supply flexibility to the DSO (discriminatory pricing).

In the model the DSO identifies possible grid problems in advance and informs the aggregators about congestion points. USEF defines a role called the 'common reference operator' set up for the exchange of information about connections, associated aggregators and congestion points. The market has five phases: contract, plan, validate, operate and settle. In [163] the framework specifications are outlined. All phases are handled in a bilateral way among the stakeholders, no centralized market clearing is proposed.

5.5 Main Characteristics of Local Market Design

There are differing opinions in literature about how actors should interact among each other. A key point of the market design is who should be the local market operator. Table 5.1 presents a summary of the differing opinions on this topic. Different points of view argue that either the TSO, the DSO, the BRP or another impartial party should be the local market operator. The choice of market operator dictates the type of market interactions that would be possible. So far, most of the literature points towards a local market for reserves operated by either the DSO or the TSO. A less seen alternative is a competitive local market, where all actors buy and sell flexibility for their own use. Figure 5.3 summarizes the main proposals regarding local market design:

- Local competitive market: a market open to competition on supply and demand.

- Local Reserves market: single buyer market, open to competition only on the supply side.

The differences between a local exchange and a reserves market are explored in the following sections. In a reserves market for flexibility, a relevant discussion arises regarding the interaction of the system operators. One trend places the

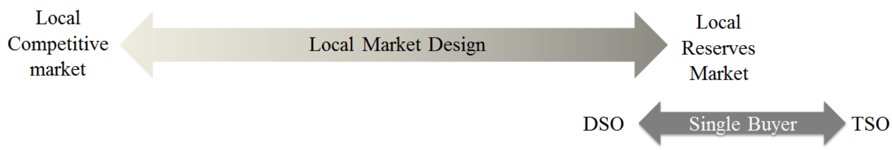

fig. 5.3. Local market design

DSO as an active system manager who has first priority over the resources connected to its grid. The other trend gives priority to the TSO in contracting all flexibility resources on both TSO and DSO grid since the TSO has the responsibility to maintain the integrity of the entire system. A local exchange allows competition on both demand and supply. It can be a bilateral agreements market, or it can be run by an independent market operator that is impartial to the transactions held within it.

5.6 Flexibility as Reserve

This section is based on: [165]

Ramos Gutierrez, A.; Belmans, R., 'DSO-TSO Interactions in Flexibility Contracting', CIGRE General Meeting, Paris 2016

TSOs have traditionally performed the procurement of grid support services in order to ensure a reliable and secure operation of the system. Load frequency control services are usually provided in three time frames after a frequency deviation occurs ranging from 10 seconds to 15 minutes. Flexibility could be thought of as a requirement in emergency situations. A band of 'technical flexibility', both upward and downward, can be defined by the DSO. In this way, a certain amount of the available flexibility is readily accessible when needed. Similarly, flexibility can be procured through limited connection contracts, where the capacity of connection is not guaranteed during a certain amount of hours per period. These two options are not considered market solutions, but rather arbitrary decisions of the system operator at hand, and are only appropriate for emergency situations. Until now, the DSO has not been involved in grid support procurement.

A semi-competitive market is one that is open to competition only on one side of the market. In this case it would be open on the supply side, but limited to a single buyer in the demand side. In a regulated market the TSO is the sole buyer who procures resources in the best interests of the network. In the local market for reserves demand for services is allowed only to the system

Reference	Flexibility Market Operator
Ruester, 2014 [112]	DSO
SEDC, 2016 [110]	Two alternatives: Extension of the TSO reserves market. Or, independent market operator: coordinated with established markets.
Fenix Project [149] [128]	TSO as a single buyer for flexibility
Ecogrid Project [154] [155]	TSO as a single buyer for flexibility
Rosen, 2015 [117]	BRP as market operator (towards individual consumers) and the TSO as single buyer of flexibility.
i-Power Project [160]	DSO as a single buyer of flexibility.
Bid-ladder Belgium	TSO
EDSO, 2015 [164]	DSO
ENSTO-E, 2015 [131]	TSO
Botsis, 2015 [125]	Multiple power utilities
EvolvDSO Project [159]	DSO role as distribution constraints market operator through long-term flexibility tendering

Table 5.1. Proposed flexibility market operator

operators. These entities become the only ones entitled to procure system reserves. Therefore competition is not allowed on the demand side. Flexibility could be contracted either by the DSO directly for resources in its grid, or by the TSO even when resources are in the DSO grid. In the latter case the DSO should have a view over the schedules of controllable resources connected to its network. Organizing a regulated market becomes an issue of hidden information, since -as of now- shifting costs for demand response are mostly undefined. For industrial consumers, the cost depends on their industrial processes and the opportunity cost of shifting. For household consumers the cost lies in the potential loss of comfort. Because of this, it is difficult to assign a monetary value to the flexibility provided by aggregated households.

As in all regulated markets the buyer has the option of regulating either price

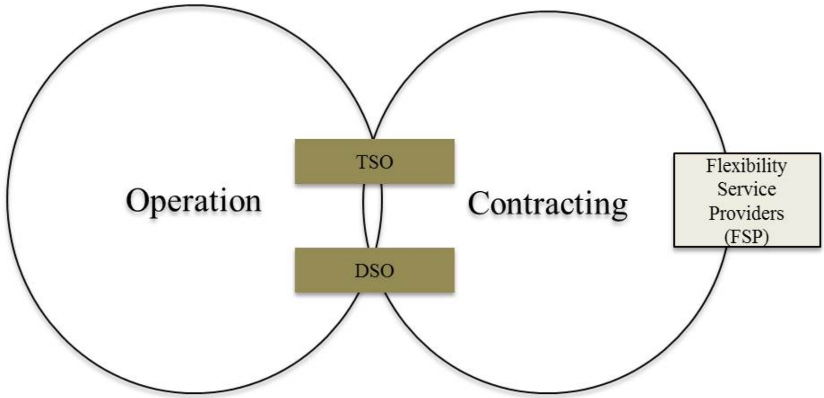

fig. 5.4. Interaction between buyers and sellers in a reserves market

or quantity. Under a price mechanism the buyer offers the market a price for reserves on the mid to long term and hopes to obtain the necessary resources. Determining this price is a challenge, but in any case it must be lower than the cost of network reinforcements. If the price is too high the buyer risks overpaying for resources. If it is too low the buyer risks not attracting enough resources to cover the needs of the network. A flat price for all reserves is not realistic given that the flexibility market in the distribution network has at least two distinct types of consumers: industrial consumers and residential consumers. Under a quantity mechanism the buyer sets a desired amount of flexibility and asks bids from qualifying market players to provide the capacity. A revelation mechanism in which two different quantity-dependent prices are offered for flexibility is proposed in [94]. The buyer would offer a higher price for a limited amount of flexibility to be able to procure flexibility from small consumers; and a lower price for a bigger amount of flexibility to procure from the rest of the market.

The question remains as to whether the resources should be centrally contracted by the TSO, or the DSO who is directly responsible for the grid where the resource is located. Figure 5.4 depicts the direct contracting interaction between the possible buyers and the holders of resources in a reserves market approach. Reserves contracting is negotiated without intermediation, directly by either system operator. In the option where the TSO is the main contractor, he contracts resources both in transmission and distribution. The TSO has a panoramic view on the state of the transmission grid overall, and the trouble areas in distribution. This is an advantage if the contracting is performed directly by the TSO, since he can use resources more widely. The disadvantage is that the TSO has no visibility on the DSO's grid, where the resource is located. This could cause problems for the DSO if the grid is overloaded. In this case the DSO needs to do a preemptive checking to see if the grid has enough capacity to cope with the flexibility being sold to the TSO. This check could be done once before the contract is signed, or dynamically in response to operating conditions. On an ex-ante basis the capacity check is carried out under a worst case scenario assumption. Possible potential for flexibility can be lost as the grid is not expected to be in the worst case scenario most of the time. On a dynamic basis, in response to operating conditions, the DSO can signal that the resource or the network area is available or not available for flexibility dispatching. The signal needs to be communicated to several parties: the TSO, the aggregator or owner of the flexibility and the balancing responsible party for that perimeter. This dynamic signaling requires availability of measuring and communication technologies across the DSO grid and the other parties involved. Currently, that is not the case in most of the low voltage grids.

In the case where the DSO would contract flexibility directly, it could be used to optimize the distribution grid operation. It is a bottom up approach in contrast to the top down TSO contracting. In this case, if the TSO were to require balancing from assets in the distribution grid, these would have to be contracted through the DSO. This is again, a semi-commercial operation not clearly defined as part of the role of either system operator. Under this method, responsibility for each individual grid remains within the domain of each system operator. Flexibility feasibility checks are still necessary, but lie within the domain of the DSO entirely for resources connected to his grid. Communication is necessary between all the involved parties. In countries where there are many DSOs, coordination between the DSO, the TSO and the wholesale market becomes critical.

The time frame of a reserves market is defined by the contracting procedure. Resources are tendered one year to six months in advance so that the system operator can be sure that they will be available when needed. The activation of resources can be notified up to one day in advance, according to grid conditions. The buyer will then decide the best moment to activate those resources according to the needs of the system at a specific moment. As such, a reserves market can be classified as a bilateral long-term market with activation in real time.

Figure 5.5 presents a simplification of the proposed approaches for flexibility contracting and the interaction of the DSO and TSO in each one. In the lefthand side of the figure the TSO approach is presented. In this scheme the TSO contracts resources directly from the flexibility provider located in the distribution or transmission network. When the flexibility provider is located in the distribution network the DSO's role is to pre-qualify the service by checking whether congestion and power quality constraints could be violated by the flexibility activation. In the right hand side of the figure the DSO

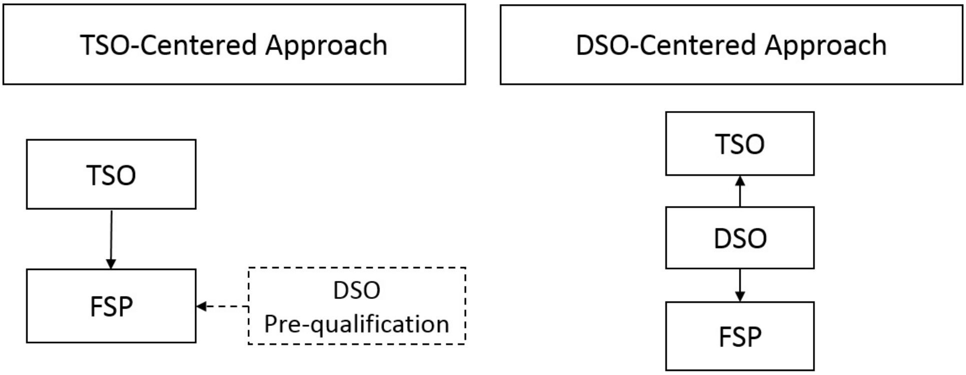

fig. 5.5. Proposed Approaches in Flexibility Contracting

approach is presented. The DSO contracts services directly from the flexibility provider in order to manage congestion. The DSO then communicates the services contracted to the TSO, and if there is no congestion the TSO can use the flexibility resource as well. This scheme implies that the DSO is actively informing the TSO about the use of the resource in the distribution grid, and that the TSO requests flexibility services through the DSO. DSO and TSO priority contracting are explained in the following subsections.

DSO Priority in Flexibility Contracting

The DSO acts as an active system manager and contracts flexibility services to manage congestion in the network. In these type of proposals the DSO directly contracts flexibility resources and has priority over their use.

The authors in [136] introduce the notion of a hierarchical market where a restriction is made to trade resources first at a local and second at a wider grid level in the absence of congestion. The European Distribution System Operators' Association for Smart Grids (EDSO) highlights the need for increased DSO-TSO cooperation [164]. They state that DSOs are responsible for the security and quality of supply of their own networks. As such, DSOs collect the data of the customers connected to their networks. Other system operators, such as the TSO, do not interact with customers connected to DSO networks. EDSO supports a model based on the concept of 'cascading responsibilities' where each system operator is responsible for its own grid and grid users. Data needs for each system operator should be defined. System planning should be coordinated between the TSO and DSO. Connection requirements for grid users should be defined by both DSOs and TSOs together. To facilitate the integration of RES, TSOs and DSOs should regularly exchange and publish information regarding their available network capacity at the TSO/DSO interface. DSOs need to procure system flexibility services and oversee their effects on the grid. The report also states that electricity markets have to evolve to take into account distribution networks and the location of generators and service providers. DSOs have to validate the technical availability of flexible resources connected to their networks in three stages: pre-qualification of the flexible resource (in terms of potential constraints on the distribution network), activation of the resource, control of energy effectively consumed or produced.

The European FP7 project EvolvDSO proposes a new role for DSOs as a 'distribution constraints market officer' [156] [157] [158]. The scheme was described in section 5.4.4. In this scheme the DSO contracts flexibility directly in order to avoid grid investment. The project recommends the establishment of a hierarchy in communication and resrouce activation between the DSO and the TSO.

The DSO-TSO interaction has been studied in Portugal in [15]. The paper studies the impact of DG on distribution networks regarding losses, voltage profile, system stability, network capacity and congestion, system balancing and reserve, short-circuit level, protection selectivity, network robustness and power quality. The authors state that DG connection might lead to change or distortion of the voltage profiles at transmission nodes. In [166] it is stated that as interaction with the TSO increases, real time information capabilities allow the DSO to perform real-time analysis of the power flow and state of the distribution grid. The information retrieved would include active power, reactive power, voltage measurement and remote automation device states. This enables the increase of distributed generation penetration. The authors in [166] study the case of a DSO in the Netherlands with a large amount of CHP plant connection. Due to the regulation, the DSO must connect CHP plants faster than they can reinforce the network. The introduction of DG also causes congestion in the local transmission grid, with a need to reinforce it. The authors propose a coordinated DSO-TSO proactive planning approach. One of the possible solutions presented is the elimination or deferral of the construction of a TSO-substation by connecting DG to the local MV-grid and accepting bi-directional power flows. This option requires investments in connection rather than in substations. These solutions are restricted by fault level, protection issues and power quality.

The European research project ADDRESS proposes a flexibility architecture where the aggregation function is provided by the retailer. The project describes the TSO and DSO as flexibility buyers and technical verifiers of flexibility services [167], [168]. They propose two options to do the technical verification: 'ex-ante' before the activation of consumers by aggregators, or in 'real time' after the market closure. Consumers providing flexibility are grouped into load areas defined by the DSO and TSO. Flexibility programmes are submitted to the system operators. A flexibility table is calculated and published before the market opening to allow participant bid creation. In a follow up publication of the same project the DSO functional architecture is divided into three control levels: a central control, an HV/MV substation level for MV network monitoring and an MV/LV substation level for LV monitoring [169]. The DSO and TSO are asked to provide information on the location of consumers providing flexibility and on whether flexibility actions comply with network constraints. In order to achieve this, the project proposes an active demand management system.

TSO Priority in Flexibility Contracting

In this scheme the TSO is in charge of contracting flexibility resources directly, even when resources are located in the distribution network. The DSO has a passive role in ex-ante pre-qualification of flexibility resources. The DSO could determine a one-time worst-case scenario and set a threshhold accordingly, or do periodic checks of the effect of flexibility resources located in the distribution network.

ENTSO-E identifies needed changes in the TSO-DSO interface in order to unlock consumers' potential as electricity generators and balancing actors [170]. The report highlights the need for DSOs and TSOs to support a market framework that unlocks the flexibility potential of consumers, and consumers should have access to participate in all markets. Also, TSOs and DSOs should work together to determine requirements for observability and active power management of DG and DSR. They state that the fragmentation of markets should be avoided, and it is preferable to have a unique marketplace for both flexibility and balancing. The report also recommends that DSOs cannot be on both sides of the market as market facilitator and service provider; if they need a system service they cannot be buyer and provider at the same time. Balancing markets should evolve to take into account and deal with operational constraints of TSOs and DSOs. In terms of operational interaction, the report states that TSOs will continue to have the leading responsibility for balancing, frequency control and system restoration, whereas DSOs will maintain their responsibility for managing their network, with an increasing need to manage distribution congestion and voltage. The report emphasizes operation and control by the TSO, even for resources connected to the distribution network:

- All active power management actions with an impact on system balancing and/or the transmission system should be overseen by the TSO and implemented either directly by the TSO, through the DSO or aggregators.

- TSOs and DSOs should cooperate on the definition of controllability procedures on DG and DSR resources and especially to find the solution to allow TSOs to curtail DG or activate DSR, wherever its connection point, in alert and emergency system states.
- It is necessary to define an efficient operational procedure when: (i) both networks are affected by congestions (i.e. who acts first, who pays, etc.), (ii) TSO balancing actions have an impact on DSOs, and (iii) DSO congestion management actions have the potential to affect the TSO network.

The Florence School of Regulation [171] recognizes that in a scenario of high decarbonization more decentralized resources are expected to develop, and it becomes necessary for the DSO and TSO to cooperate. The report identifies balancing decisions in one network that could affect the other network. They propose that congestion management decisions at distribution level should be neutral for the transmission system or should include an imbalance fee. Similarly, decentralized resources used for managing the transmission system should consider their declared price in the balancing market as well as their shadow cost for the distribution system. The report envisages three solutions:

- DSOs operate their system according to the format of their respective TSOs.
- The transmission system operator expands its operation to the distribution system.
- TSOs and DSOs share a security cooperation initiative.

Market rules should adapt to the new resources while allowing aggregator participation. The authors in the report expect new transmission tariffs for generators related to locational incentives. Consumer tariffs would need to be updated to reflect this change.

In [172] the need for transmission grid interfaces with distributed resources is described through the use of smart substations that incorporate microgrids and can operate in islanding mode.

5.7 Local Competition for Flexibility

As a separate platform, the market could be operated only on the local level and unrelated to the wholesale market. Competition is allowed on both the

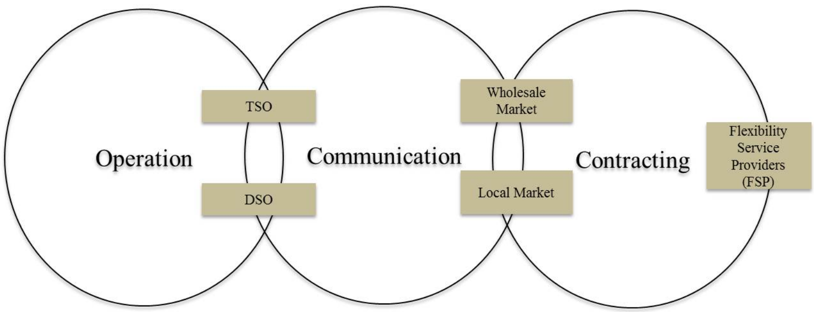

fig. 5.6. Interaction between buyers and sellers through a local market exchange

supply and demand sides of the market, making this a competitive market. The market could either be bilateral or run as an exchange.

The design of the local market mirrors the wholesale market in temporal, contractual, and price clearing dimensions, but it has a specific spatial component. Figure 5.6 depicts the interactions between the system operators, the market and the flexibility service providers. The DSO and TSO must coordinate the grid operation and use of resources between each other. They could issue requests for flexibility services to the markets when needed by the grids. These requests must contain information about the required time, amount and location of the services. Similarly, market participants can place requests for flexibility when they have balancing needs in a specific area. The market matches the requests for services with available resources, and an efficient communication between markets ensures that resources are only booked once. Flexibility providers offer flexibility services to the markets, either directly or through an aggregator. There is the risk that the local exchange will compete for resources with the wholesale market. To avoid this, it should be designed as a hierarchical market in case of congestion. This means that the same resource should not be contracted, and paid for, twice. This is a similar design to the relationship between long-term and short-term markets, where results are transferred from one market to the next or directly to the system operator. In this manner, a local flexibility market will always be linked to the wholesale market, and indeed can be a participant of it. In unconstrained conditions, the local market would not be necessary, and the energy price across all regions would be the wholesale market price. Only during congestion would an area exhibit a price difference from the wholesale market.

There is a debate as to who should operate this platform. The system operators, both the TSO and DSO, hold the information about the needs of the grid. As regulated businesses they have limitations on the type of commercial activities they can engage in, and so would require regulatory changes to be allowed to run a competitive exchange. TSOs are currently able to purchase balancing power through market mechanisms while DSOs are not. The discussion is similar to the one presented in subsection 5.6. The TSO holds visibility over the wider network, but not over the network of the DSO. While the DSO cannot foresee how the deployment of resources in his network will affect the TSO or other DSOs. An independent operator would be a purely commercial third party who would need to rely on requests for services provided by the system operators. Furthermore, the system operators need to be able to see each others' requests so as to take into account the impact of these activations on their networks.

An exchange platform in electricity markets is used to balance portfolio positions in the day-ahead and real-time horizons. Available flexibility is needed to cover differences between forecasts and actual generation and consumption. Therefore the time horizon of a flexibility platform itself is in the short term. Flexibility service providers, however, need to arrange contracts in advance so that the flexibility will be available in real time. For example, an aggregator can set up contracts for a pre-defined number of demand response load reductions per year. The aggregator will then need to optimize available resources and decide which ones will be offered in the short-term markets.

5.8 Conclusion

Locality in this context refers to a specific geographic location, grid connection, and system operator pertaining to a set of load and generation. Local flexibility contracting is a growing need in face of the fast integration of DER resources. On the one hand, stakeholder groups have issued opinions regarding the need for organized local flexibility contracting. On the other hand, the study of local flexibility has taken a mix of technical trajectories, such as microgrids, and commercial ones such as virtual power plants. Most studies do not bring together both technical aspects and the commercial interactions and purposes of the involved stakeholders. This thesis contributes a unified definition of local market: 'long- or short- term trading actions for flexibility in a specific geographical location, voltage level, and system operator (DSO and TSO), given by grid conditions or balancing needs, where participants in a relevant market can be aggregated to provide flexibility services.'

Current local market design proposals in literature and ongoing projects are presented. It can be concluded that there is no unified market design, and no agreement on who should undertake the key roles. The main trends observed place either the TSO, the DSO or an independent market operator as a buyer of flexibility. It can be concluded that the first two points of view call for a regulated reserves type market design, given that both the TSO and DSO are regulated parties. It would be a reserves market open for competition only on the supply side, with a single buyer. Similarly, there are differing points of view on which of the two system operators should have priority for the use of flexibility.

In the DSO-priority approach the DSO contracts flexibility to be used for grid purposes directly from the flexibility service providers (FSPs). This flexibility can later be used for the DSO's own grid needs, re-sold to the TSO or to a third party that may need it. The main benefits of a DSO-priority model are: avoiding double booking of resources, enabling visibility of flexibility to the DSO at all times, and promoting local grid management. The downside of this model is that it creates transaction costs for the DSO in case that it doesn't need to use the pre-contracted flexibility resources. Also, this model implies that a priority is given to the DSO in the use of flexibility, which might not always be necessary.

In the TSO-priority approach, the TSO is the first one to have the one access to all flexibility resources, including those in the distribution grid. It can be argued that this is a fair approach since the TSO holds the responsibility for balancing the system as a whole and has a more thorough vision. In an opposite view, it implies that the TSO is contracting and then activating flexibility resources in the distribution network, without having visibility of that particular network. A clear division of responsibilities and communication protocols is necessary for this model to work.

The optimal solution depends on the topology of the system, the amount of DRES connected to a distribution grid, and the available flexibility resources. The introduction of more DRES, storage and electric vehicles in the future may cause or need an increase in DSO-TSO cooperation in terms of contracting, information sharing, and operation.

The topic of the TSO-priority in flexibility contracting, while relevant, has already been more studied and implemented than the DSO-priority. Therefore this thesis contributes to the state of the art by focusing on the two cases presented above under a scenario of DSO-priority. Table 5.2 presents the main characteristics of market design for each of the main trends for each local market design under study. In both instances, the local market is initiated by a location specific need determined by the DSO. In the rest of this thesis, two main alternatives will be analyzed from the point of view of an active DSO:

- Chapter 6 presents a DSO market for flexibility as reserves in order to solve congestion issues.

- Chapter 7 presents a case of competition for flexibility where the DSO competes with the BRP in order to buy flexibility from a profit maximizing aggregator.

Both markets start from a local need dictated by grid congestion. A study of when this congestion occurs and what its value is for the DSO is presented next in chapter 6. Flexibility contracting directly by the DSO through a reserves type market is studied in chapter 6. A profit maximizing aggregator and a BRP are introduced in a competitive scenario in chapter 7.

Dimension	Local Reserves Market	Competition for Flexibility
Temporal	The DSO decides whether to buy flexibility or invest in grid expansion at the beginning of a period of time. Long-term contracts are used for assuring availability of reserves coming from aggregators. Flexibility is activated in real time.	The DSO has a long-term demand for flexibility and the BRP has a short term one.
Spatial	The DSO issues a request for flexibility to the aggregator managing resources that can solve a network need. The specific location of the aggregator's resources will determine the available flexibility supply.	Bids are specific to a predefined area given by grid constraints. Communication with the DSO is used to identify network needs. The DSO and BRP place requests to a profit maximizing aggregator based on local needs.
Contractual	Flexibility availability is procured through tenders for quantity issued by the DSO. Contracts are bilateral.	Contracts are bilateral between the aggregator-DSO or aggregator-BRP. The aggregator must decide in advance whether to contract with the DSO or the BRP.
Price Clearing	The DSO remunerates flexibility using a pay-as-bid method.	The DSO and BRP submit bids for flexibility to a profit maximizing aggregator. The highest bids are accepted first and allocated according to availability of flexibility.

Table 5.2. Dimensions of the proposed local market designs

Chapter 6

DSO Market for Reserves

Distribution grid management is challenged by the introduction of new technologies. Load profiles are expected to change with the growth of electric vehicles, small-scale storage, and solar panels at users' homes. For example, figure 6.1 shows expected global scenarios for the deployment of electric cars up to 2030 according to the International Energy Agency [173]. As electric vehicles are integrated into the distribution grid the need for local congestion management will be more evident [174]. Electric vehicles need to be charged so that they are ready for use when drivers leave their homes or jobs. Home users will be able to change their expected load patterns through the use of battery storage to take advantage of either price signals from the market or their own production from solar panels. In addition the grid needs to handle the growth of distributed generation such as small combined heat and power and wind generation.

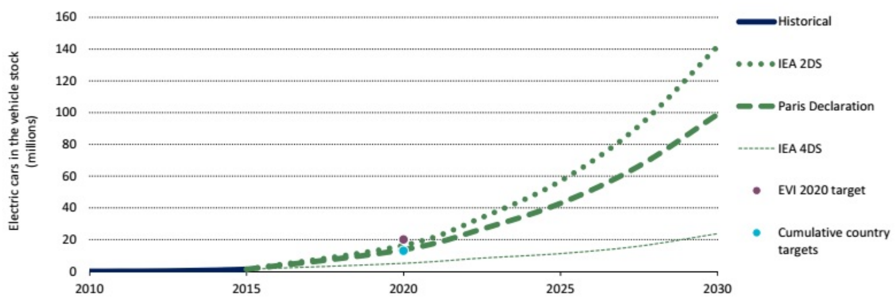

fig. 6.1. Deployment scenarios for the stock of electric cars to 2030.

It was determined in chapter 5 that the specific need for a local market stems from grid conditions. These conditions need to be recognized by the DSO and communicated to other parties so that action can be taken. In this case, expected congestion in the DSO grid is analyzed as the cause of a need for either flexibility contracting in the form of demand response or grid expansion.

This chapter has three main purposes:

- Analyze and quantify the DSO's demand for flexibility;
- Study the value of flexibility for the DSO;
- Propose a decision making model where the DSO decides to either invest in grid reinforcements or buy flexibility.

The results from the wholesale market as given in chapter 4 are passed on to a test network in order to determine possible local flexibility needs.

The DSO's demand for flexibility, that gives the location specific component that creates a local market, is examined in section 6.1. Once the quantity demanded is determined, its value to the DSO is explored in section 6.2 in terms of either purchasing flexibility at cost value or investing in grid expansion. A methodology to take this decision is proposed in 6.3. In order to test the model data needs to be created as explained in section 6.4. Input data for the network and decision model is described in 6.5. Illustrative results for the DSO's demand for flexibility are presented in 6.6.2, and results for the decision model are explained in 6.7. Chapter conclusions are given in 6.8.

6.1 The DSO's Demand for Flexibility

Usually when a new connection is requested to a distribution network, an analysis is done to see if the expected flows with the added connection would violate network constraints. If limits would be violated network reinforcements are proposed. Distribution grids are planned to have enough transfer capacity to cover the expected peaks plus safety factors for reliability. Therefore they tend to have a relatively low utilization factor. In the examples that follow it is assumed that the grid capacity limit presented has already deducted reliability margins, and is the actual capacity that load and generation can use.

Figure 6.2 exemplifies a load duration curve where load is organized ranging from highest to lowest throughout an entire year. Grid capacity is represented by the solid grey horizontal line. Hours of expected peak loads during a year are

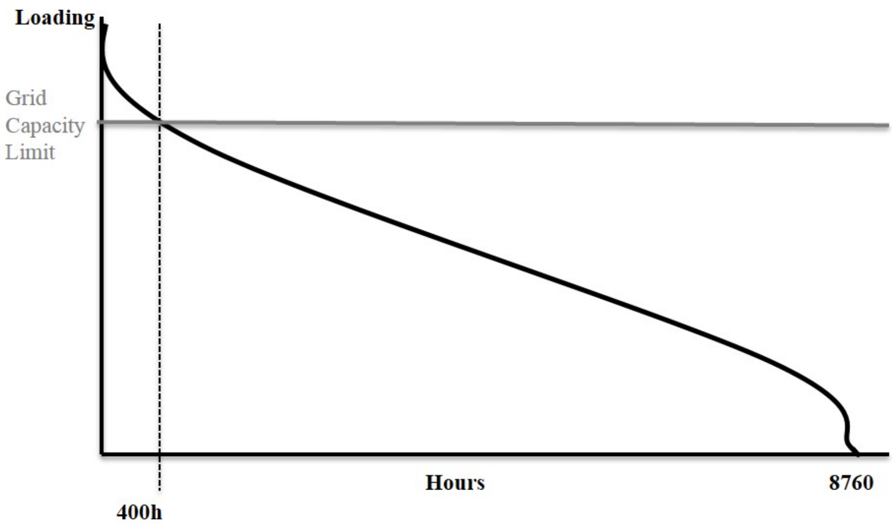

fig. 6.2. Load duration curve and grid capacity limit

limited, in this example to 400h. Reinforcing the network to satisfy the peak load might be too expensive taking this limited need into account. As the network is more than strong enough to satisfy periods of low to mid demand, reorganizing load, through demand response programs, would be a better solution. Figure 6.3 exemplifies average consumption throughout a day with respect to the grid capacity limit. The dashed line represents the current load profile, and the shaded area represents the potential for strategic load growth. It is necessary to avoid more demand at peaking hours and encourage consumption during valley hours. In this way, the existing grid capacity can be used to it's full potential.

Continuing with the current approach, investing to accommodate all peaks, might prove too expensive to society. Active grid management is a way to help the system accommodate new technologies while managing grid investment costs.

The DSO's demand for flexibility is derived from moments when the network experiences congestion that could be solved through either demand or distributed generation modifications at a given time. The DSO needs to have tools to foresee in advance when this congestion would occur and decide whether flexibility contracting is the optimal solution as opposed to network reinforcements. The DSO needs to make this decision in the long term time frame in order to have enough time to reinforce the grid in case flexibility is not available. The proposed demand for flexibility and the decision analysis that follows takes

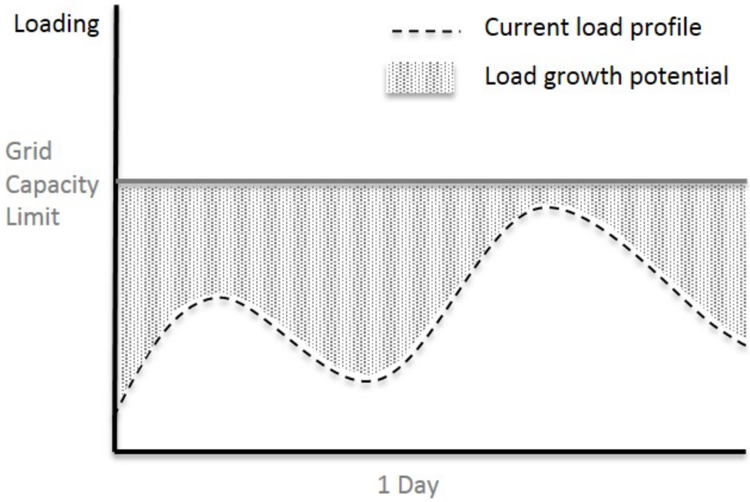

fig. 6.3. Grid potential to accommodate load growth

place at the beginning of an evaluation period, in this case one year.

Congestion in a distribution grid refers to when the demand for active power transfer exceeds the transfer capability of the grid [175]. The transfer capability of the grid is related to voltage limits, thermal limits of cables and transformer and protection settings. This thesis deals with the active power capability of the grid.

Congestion issues in distribution have been traditionally solved either through reactive and voltage control or load and distributed generation curtailment [176]. Other options include grid reconfiguration strategies to avoid overload of feeders and transformers [177]. This chapter deals with solving congestion through market based flexibility of the users connected to a particular grid.

6.1.1 Demand for Downward Flexibility

Continuing with the example above, the DSO would need downward flexibility when the expected load profile exceeds the grid capacity limit. Figure 6.4 represents a case when the expected load at a certain feeder in the distribution grid exceeds the grid capacity. The dashed line represents the expected load profile. It can be observed that the expected peak load is higher than the capacity allocated for user transactions. The striped area represents the amount

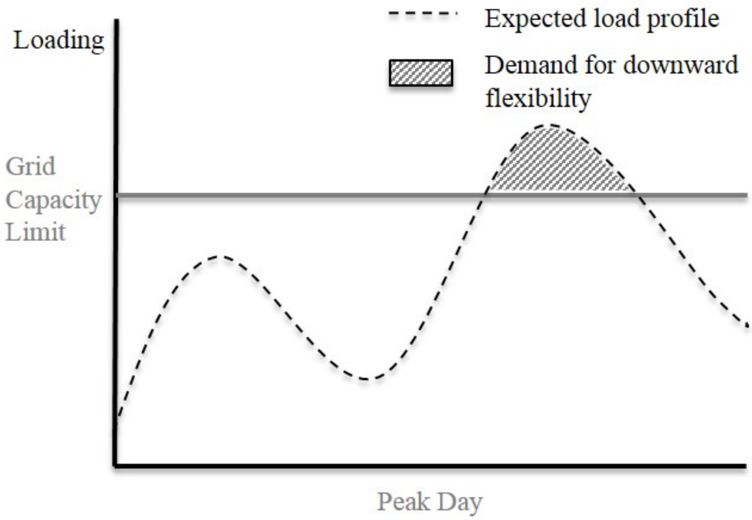

fig. 6.4. Expected congestion due to peak load conditions creates a Need for Downward Flexibility.

of energy out of bounds of the set grid capacity limit. This amount of energy would need to be shifted to a non-peak period. This means, that during those hours the DSO has a need for downward flexibility. If consumers would decrease their demand, shifting it to valley hours, the grid's capacity limit would be maintained.

6.1.2 Demand for Upward Flexibility

In this case renewable energy generation, or any other DER, covers the entire local load demand. The residual load curve is created by subtracting local generation to the expected load. The situation is depicted in figure 6.5. The dotted line represents the residual load curve after subtracting RES generation to the expected load represented by the dashed line. Energy above zero is the traditional expected load consumption in the feeder. There also 'negative' energy, meaning that the feeder is exporting energy to the larger grid instead of importing. In this example, the striped area represents a case where the expected RES exports exceed the grid capacity limit. Which means that, during those hours, the DSO has a need for upward demand flexibility. If consumers would increase their demand they would use the excess RES being produced and the grid's capacity limit would be maintained.

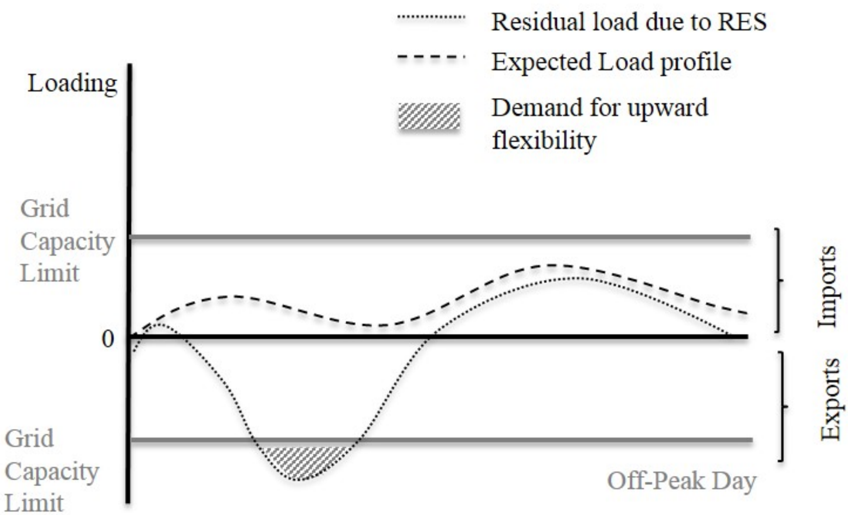

fig. 6.5. Expected Congestion due to Excess Distributed RES Generation Causes a Need for Upward Flexibility.

6.1.3 Quantifying the DSO's Need for Flexibility

The need for flexibility of the DSO is determined by assessing when the power at the slack ps_t at the substation would be higher than the transformer capacity defined by (6.1). The DSO faces a need for downward flexibility, meaning a decrease in demand across the feeders or an increase in generation as given by the $DSOdown_t$ in (6.2). In the opposite case the need for upward flexibility $DSOup_t$ is defined in a similar way by (6.3) and (6.4). It happens when there are backflows, meaning energy flowing from the DSO secondary side of the transformer to the TSO primary side would be higher than the transformer limit.

$$for \quad ps_t > trafolim \tag{6.1}$$

$$DSOdown_t = ps_t - trafolim \tag{6.2}$$

$$for \quad ps_t < -trafolim \tag{6.3}$$

$$DSOup_t = ps_t + trafolim \tag{6.4}$$

where

ps_t	power at the DSO slack node at time t [MW]
$trafolim$	power limit of transformer [MW]
$DSOdown_t$	DSO need for downward flexibility at time t [MW]
$DSOup_t$	DSO need for upward flexibility at time t [MW]

6.2 Cost and Value of Flexibility for the DSO

6.2.1 Ideal Payment for Flexibility

The ideal payment for flexibility should be based on the marginal costs for the final flexibility service providers of supplying that flexibility. These costs are largely unknown since they depend on the type of consumer as described in section 2.3. When consumers modify their consumption behavior they incur a cost. This might be the cost of running a local generator for an industrial consumer, or the inconvenience caused to domestic consumers. These costs vary for each consumer segment, along with the availability to respond to market conditions. They will not participate in a program where they incur in losses. The cost incurred by consumers due to participation in DR programs is assummed to be unknown to the market designers or demand aggregators [178].

6.2.2 DSO Incentives to Consumers for Flexibility Services

This sub-section is based on: [179]

Spiliotis, K.; Ramos, A.; Belmans, R., 'Demand flexibility versus physical network expansions in distribution grids', Applied Energy, Volume 182, 15 November 2016, Pages 613-624, ISSN 0306-2619

It was shown in section 6.1 how the DSO could use flexibility in order to avoid grid reinforcements. The DSO would be motivated to use demand response if doing so is cheaper than the avoided costs of reinforcing the network. Thus for the DSO the benefit of using flexibility is the savings in grid reinforcements achieved. These savings, SAV_{DSO}, can be defined by (6.5) where C_{exp} is the cost of grid expansion, and C_{flex} is the cost that the DSO pays for flexibility. Figure 6.6 represents the relationship between the expected costs for the DSO on the y-axis and the expected growth in residual peak-demand in the x-axis [179].

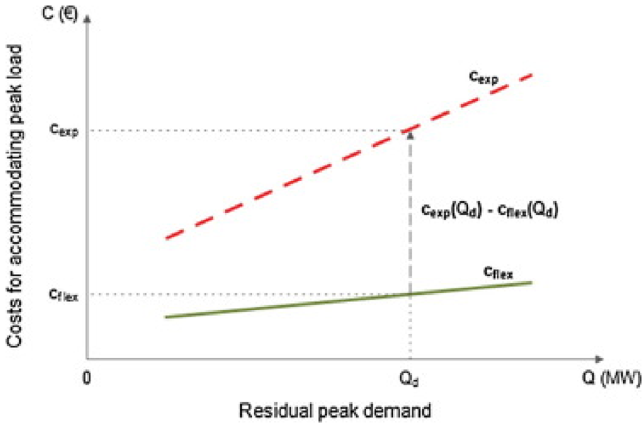

fig. 6.6. Investment deferral savings due to the use of demand flexibility.

The difference between the costs of expansion minus the costs of flexibility represent the benefit that the DSO incurs through the use of flexibility.

$$SAV_{DSO} = C_{exp} - C_{flex} \tag{6.5}$$

A mechanism to distribute the rents BEN_{DSO} from the expected savings of flexibility to the final flexibility service providers is proposed [179]. It is stated that the benefit, b_n, of supplying flexibility for the final consumer n is the price benefit of optimally shifting demand. The price benefit for the consumer is observed in (6.6). In the study, it is assumed that consumers pay wholesale market prices, MP_t, as their energy tariff. Consumers optimize shifting to save money by decreasing consumption at high price hours, $flexdown_t$, and increasing it during low price hours $flexup_t$.

$$b_n = \sum_t (\lambda_t * (flexdown_t - flexup_t)) \tag{6.6}$$

The profit sharing mechanism in the study assumes that the price benefit might not be incentive enough for consumers to modify their demand. An additional compensation from the DSO to the consumer is proposed as explained in (6.7). This compensation is meant to cover the costs the consumer would incur in flexibility provision assuming a certain investment cost of flexibility C_{flex} and an expectation of a return on investment ROI minus the price benefit b_n of shifting flexibility.

$$Compensation_n = C_{flex} * (1 + ROI) - b_n \tag{6.7}$$

A grid investment model for a radial network is proposed where the DSO minimizes costs. The DSO decides whether to invest in line reinforcements or to procure flexibility, taking into account that the DSO pays for the cost of expansion, a cost of flexibility and for any RES that is curtailed due to congestion in the network at the given market price.

It was found that at the proposed market prices, during the three year evaluation period, the price benefit b_n of shifting demand was lower than the costs the consumer incurred in investing in flexibility provision, estimated at $380 per household averaged from data found in [24]. It was concluded in the study that through the use of flexibility the DSO needs to perform up to 89% less grid expansions than without using flexibility depending on the feeder topology.

6.2.3 Value of Flexibility for the DSO

The study examined in section 6.2.2 states the value of flexibility based on an investment cost for the final flexibility service provider needed to supply flexibility. This assumption was made because the marginal costs of supplying demand response flexibility present large variations in literature. A study places the intrinsic variable cost of providing demand response in a range between 50 and 300 €\MWh [180]. Costs vary depending on the nature of the provider of demand response, eg. a household would have a different cost than an industrial consumer. In addition, the costs of aggregation need to be taken into account. The aggregator itself incurs costs in contracting, communication, decision making and information management.

Equation (6.8) expands and generalizes the rationale used in [179]. For a flexibility provider n the cost of providing flexibility can be defined as the amount of downward flexibility $flexdown_t$ times the cost of decreasing consumption $costdown_t$, plus upward flexibility $flexup_t$ times the cost of increasing consumption $costup_t$ minus the price benefit of providing flexibility as defined in (6.6).

$$Costflex_n = \sum_t (flexdown_t * costdown_t + flexup_t * costup_t) - b_n \tag{6.8}$$

Note that the internal costs of providing flexibility $costdown_t$ and $costup_t$ are different from the market price and include costs of communication and aggregation. These cost concepts are treated as unknown information, since the specifics of final demand response providers is not the scope of this work. They are included in this section for completeness, but will not be used in the analysis that follows. Rather, it is assumed that the DSO procures flexibility according to its valuation of it.

A simple methodology to calculate the cost of distribution grid investment is used based on [181]. A more detailed calculation of the cost of distribution grid investment is out of the scope of this thesis. The methodology used in [179] is expanded to convert a cost of €\MW to a €\MWh cost of flexibility that is used later in this thesis. The cost of grid expansion is shown in (6.9). Thus the cost of grid expansion in €\MWh, C_{exp}, is equal to the cost of grid investment, C_{inv}, divided by the expected useful life of the asset $life$ in years, times an average of full load hours $avgload$.

$$C_{exp} = \frac{C_{inv}}{life * avgload} \tag{6.9}$$

6.3 DSO's Investment Versus Flexibility Decision

The DSO's decision lies in whether to invest in grid expansion exp or contract flexibility $qaggup_t$ and $qaggdown_t$ in order to manage local congestion. In this formulation of the problem, the DSO minimizes total costs in the scenario that aggregated consumers provide flexibility directly to the DSO. The objective function is represented by equation (6.10). The aggregator in this case is passive and does not make decisions. The DSO buys downward flexibility $qaggdown_t$ at cost value $DRCOST$ minus the price benefit that consumers get from using flexibility. The price benefit is defined by the peak/off-peak tariff that consumers pay for the rebound demand $qaggup_t$ plus the savings from decreasing demand $qaggdown_t$. If the expected congestion is not covered through demand response then the DSO must invest in grid expansion exp at a given investment cost per MW $INVCOST$. It is assumed that $INVCOST$ represents the annualized cost of grid investment, as the decision to buy flexibility defers investment for one year.

$$\sum_t \{qaggdown_t * DRCOST$$

$$- POP_t * (qaggup_t + qaggdown_t)\}$$

$$+ exp * INVCOST \quad (6.10)$$

where

$qaggdown_t$ total downward demand response offered by aggregated consumers at time t [MWh]]

$DRCOST$ cost of downward demand response offered by aggregated consumers [€\MWh]

POP_t Peak and off-peak tariff faced by the consumer at time period t [€\MWh]

$aggup_t$ total upward demand response offered by aggregated consumers at time t [MWh]

exp total grid expansion needed to relieve congestion [MW]

$INVCOST$ annualized grid investment cost per MW [€\MW]

Subject to:

$$qdsodown_t + qdsoup_t \leq exp \qquad \forall t \quad (6.11)$$

$$qdsodown_t + qaggdown_t \geq DSOdown_t \qquad \forall t \quad (6.12)$$

$$qdsoup_t + qaggup_t \geq DSOup_t \qquad \forall t \quad (6.13)$$

$$qaggdown_t \leq AGGMAX * u_t \qquad \forall t \quad (6.14)$$

$$qaggup_t \leq AGGMAX * v_t \qquad \forall t \quad (6.15)$$

$$u_t + v_t \leq 1 \qquad \forall t \quad (6.16)$$

$$\sum_{t24} \{qaggup_t - qaggdown_t = 0\} \qquad \forall t24 \quad (6.17)$$

where

$qdsodown_t$ total downward congestion covered by the DSO through grid expansion at time t [MWh]]

$qdsoup_t$ total upward demand congestion covered by the DSO through grid expansion at time t [MWh]]

$DSOdown_t$	total requested downward demand response by the DSO at time t [MW]
$DSOup_t$	total requested upward demand response by the DSO at time t [MW]
$AGGMAX$	total available demand response by aggregator [MW]
u_t	binary variable for downward demand response activation [0 1]
v_t	binary variable for upward demand response activation [0 1]
$t24$	a subset of t representing 24 hours

The total amount of grid expansion required is set by constraint (6.11), where the DSO covers an amount of upward plus downward congestion $qdsodown_t$, and $qdsoup_t$ limited by the total amount of grid reinforcement exp decided by the model. In (6.12) the DSO's need for downward flexibility, $DSOdown_t$, to solve congestion must be met by either grid expansion as mentioned before, or flexibility provided by aggregated consumers $qaggdown$. Equation (6.13) represents the same concept for upward flexibility. Equations (6.14) and (6.15) limit the allocation of flexibility $qaggup_t$ and $qaggdown_t$ to the total available capacity of demand response that the aggregated consumers can provide. These capacities are multiplied by auxiliary binary variables u_t and v_t that ensure that upward and downward demand response are not activated at the same time as defined by (6.16). Finally (6.17) defines the rebound effect, all downward and upward demand response must equal to zero within a horizon of 24 hours.

Note that it is assumed that grid connections that are expected to violate network limits have been allowed, under the premise that the excess can be managed through the use of flexibility. Traditionally, if a new connection is expected to violate network limits reinforcements have to be made. This evaluation process for the DSO is on a long term time frame, as network reinforcements need to be planned in advance.

6.4 Dataset Creation Methodology

A feeder configuration is chosen to represent MV-LV grid connections with the purpose of evaluating the state of the DSO network in view of changing RES scenarios. Congestion is calculated at the connecting TSO-DSO substation. Thus, the need for local flexibility of the DSO is defined through the use of this methodology.

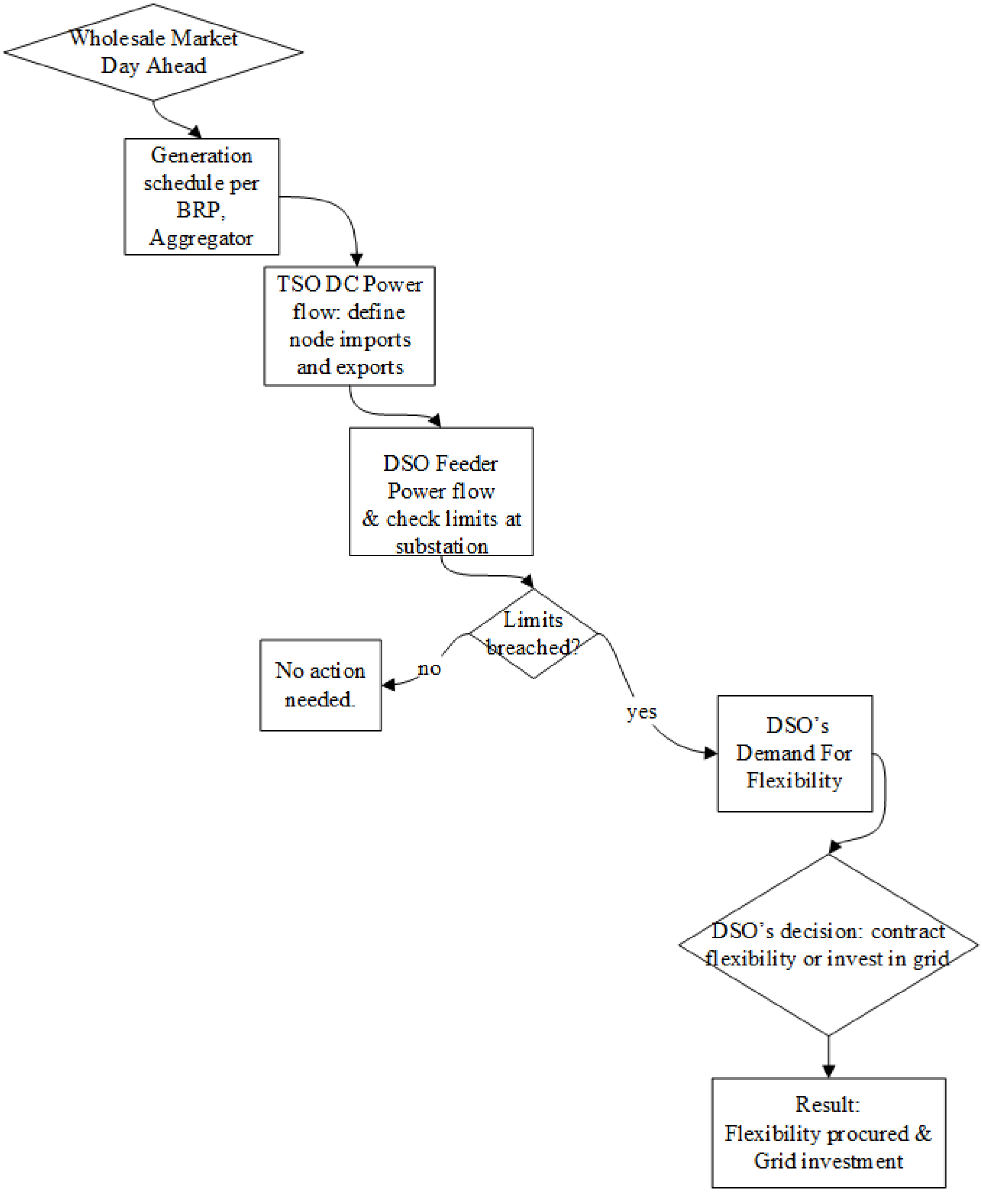

fig. 6.7. Dataset creation methodology.

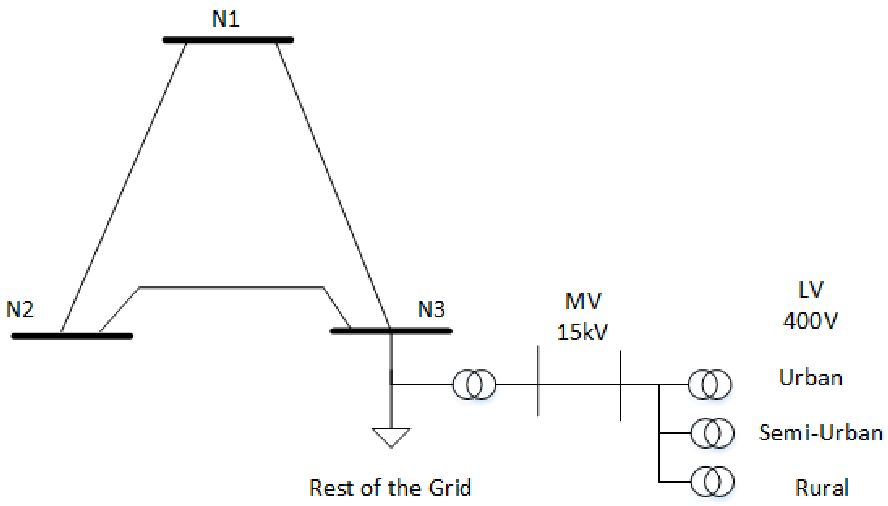

fig. 6.8. Representation of the test network used for the study.

In order to obtain a power profile related to the day-ahead wholesale market presented in chapter 4, the results are passed on to a simple three node network. One node is chosen for further study based on the results of a transmission power flow. The goal of this optimization is to find out an optimal power flow in the transmission system based on the wholesale market results, as given by the variable $p_{n,nn,t}$. A complete derivation of the DC power flow can be found in [182]. The TSO's optimization is set up so that the power flow in the lines is minimized and a unique solution exists in the problem. Figure 6.7 depicts the process that was used to create the dataset for the DSO's demand for flexibility to arrive at an optimal decision between flexibility procurement and grid investment.

In order to study the DSO-TSO interaction a two node test network is set up. One node represents a distribution system MV connection and the other node groups three chosen LV nodes. Node 1 is an abstraction of a portion of the power coming from the TSO, and node 2 has grouped three LV nodes based on [183]. Figure 6.8 shows a representation of the network used for the study.

A backward forward sweep based on [184] is used to carry out the load flow analysis given the input load and RES availability at each node. The analysis defines the power profile at each node as well as the slack value that is assumed to be provided by the transmission grid ps_t. The analysis is done for 15 minute time periods in order to account for intraday variations in RES power profiles.

node	Generation Resource	Marginal Cost	Installed Capacity [MW]
n1	BRP1g1	10	1200
	BRP3g1	86	690
	BRP3W	0	650
	BRP3PV	0	760
n2	BRP1g2	37	1000
	BRP2g1	37	700
	BRP3W	0	650
	BRP3PV	0	760
n3	BRP2g2	63	700
	BRP4g1	86	400
	BRP3W	0	650
	BRP3PV	0	760
	AGG1	15	200

Table 6.1. Available resources per node

The highest power value for each hour is chosen as the value that is requested in the energy market. Power, rather than energy values, are used to take into account the expected peaks in demand that the network will face. Power values are used for distribution network planning in [185]. Energy values, meaning the average of the power data for each hour, are not used since intra-hourly peak variation would be lost. Since the purpose of the methodology is to accommodate renewable energy, it was estimated important to observe peaks even if the final results might lead to over dimensioning of the network.

6.5 Input Data

The results of the wholesale market are split into three equal parts and passed on to a TSO DC load flow consisting of three nodes. The resulting generation and resource schedule takes into account the energy scheduled for each generation unit, the decided wind and PV curtailment, and the changes in demand caused by demand response. Generation availability is defined per node in table 6.1.

6.5.1 Transmission Grid Data

Grid characteristics have been extracted from [186]. The three cables connecting each node are assumed to be equal (table 6.2).

line	**r [pu]**	**x [pu]**	**Line Limit [MW]**
L1-2	0.029	0.32	1350
L2-3	0.029	0.32	1350
L3-1	0.029	0.32	1350

Table 6.2. Transmission line characteristics

Transformer	V1	V2	PNOM
T1	70 kV	15 kV	30 MVA
T2	15 kV	420 V	400 kVA

Table 6.3. HV-MV transformer characteristics

6.5.2 Distribution Grid Data

The distribution grid used in the analysis consists is a medium voltage grid of 15 kV. The transformer data used is taken from [186] and shown in table 6.3.

Two levels are considered in order to include residential profiles containing solar power connected to the network. However, for purposes of the analysis all data is aggregated into the MV layer at the transformer T1 that connects the distribution to the transmission grid.

In order to study the interaction between the TSO and the DSO an MV-LV network is set up based on the results of node 3 in the transmission network. The MV feeder includes 10% of the load and RES data coming from the previous TSO DC load flow in addition to the data from the three load voltage feeders. It is assumed that the rest of the energy is going towards other MV feeders, and that all thermal production in node three is located at the transmission level. Load after the demand response actions in the wholesale market is included in the scaled analysis as this is the value that the DSO would need to manage. Figure 6.9 shows the load data for the evaluation period scaled from the results for node 3 in the TSO load flow (top), and the input wind and solar profiles (center and bottom) respectively for the evaluation period. All data is hourly for one year.

The MV feeder is then connected to three LV feeders, representing urban, semi-urban, and rural grid scenarios that contain PV production as well. The feeders have been chosen based on [183], where typical feeders in Flanders have been simulated.

Figure 6.10 represents the input power profile of the three LV feeders for the entire evaluation period. The figure represents the results of the three 400V feeder load flows. Positive values represent power flowing towards the feeders,

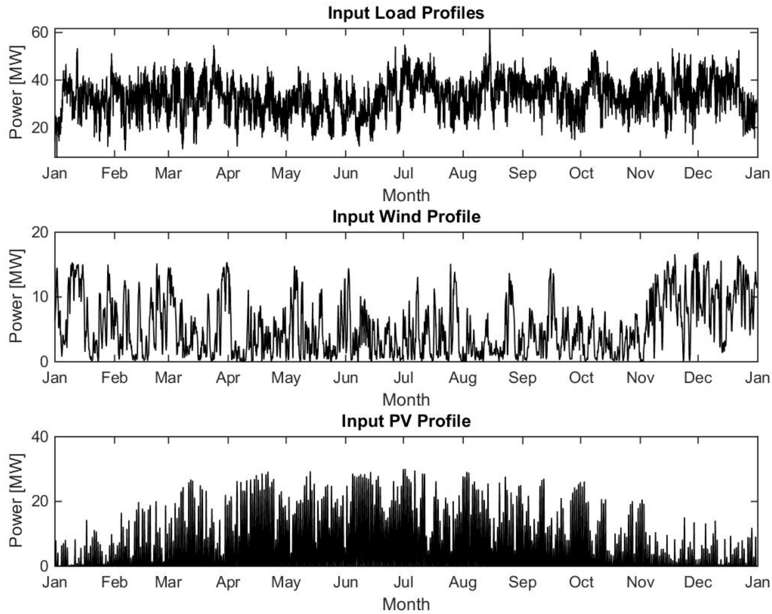

fig. 6.9. Input load data at the MV feeder coming from the transmission system load flow (top), and the wind and solar profiles (center and bottom) respectively for the evaluation period.

and negative values represent backflows from the LV feeders toward the MV network. This happens because there is solar power production connected to the houses in the feeders. Predictably, the urban feeder is the largest one, amounting to around 1 MW of power at peak hours. For simplicity in the analysis, the three nodes have been grouped into a single value of consumption for every period of time. The time period resolution for the distribution system analysis is hourly.

6.5.3 Cost of Grid Expansion

Based on available literature and conversations with industry experts it is estimated that the cost of investment in distribution lies somewhere in between 6,000 €\kW and 10,000 €\kW [187], [188]. In a whitepaper by the International Electrotechnical Commission several studies about the lifetime of components

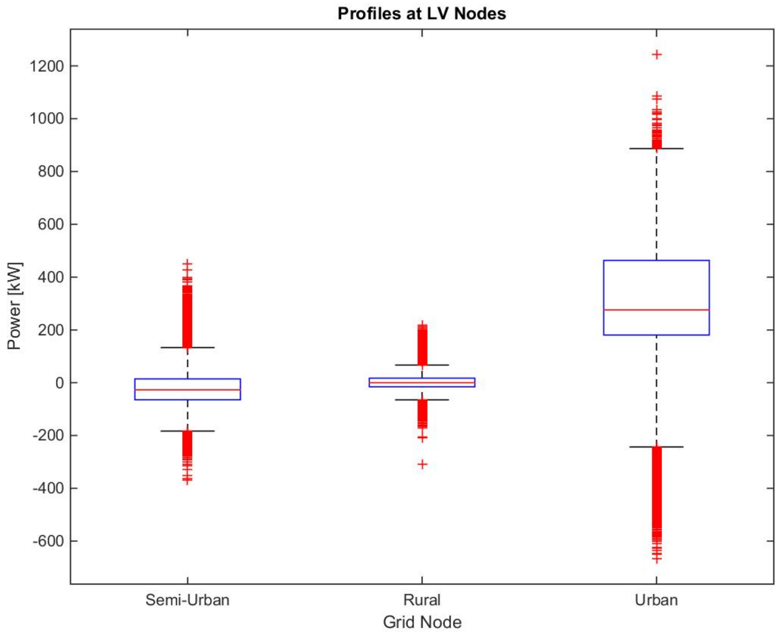

fig. 6.10. Input power profile of LV feeders.

in power systems are summarized. Most components are estimated to have a service life between 25 and 50 years [189].

In the analysis that follows, an average cost of grid expansion of 8000 €\kW is assumed. The assets are depreciated linearly for a useful life of 25 years. This yields a yearly cost of 320,000 € per MW installed.

In chapter 7 a cost per MWh is used and calculted according to 6.9. An average load of 2000 hours, and a useful life of 25 years is used [181]. Taking into account a cost of investment of 8,000 €\kW, the hourly cost of investment amounts to 160 €\MWh. This methodology proposed by the International Energy Agency [181].

6.6 Results for DSO Demand for Flexibility

First, the results of the HV power flow are presented for the three node network in consideration. Then, these results are scaled and passed on to the MV

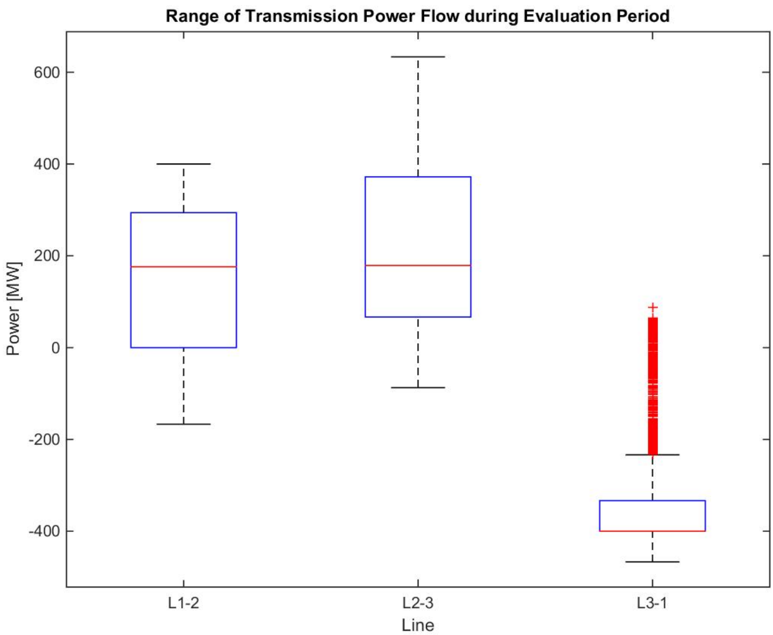

fig. 6.11. Box plot analysis of power flow in each line of the transmission system.

network described above.

6.6.1 Dataset Created for Distribution Network

The results of the power flow analysis in the transmission system over each line can be observed in figure 6.11. Positive values mean power flowing in the direction indicated in the line name, and the opposite for negative values. For example, L3-1 represents the power flowing from node one to node three. As the values are mostly negative, it means that most of the time power flows form node one to node three through L3-1. The graph analyses the data through a box plot, the middle line of each plot represents the median of the values. The box represents the values where 50% of the data fall and the upper and lower whiskers represent the top and bottom quartiles of data respectively. In the results this means that for lines L1-2 and L2-3 most of the values fall between zero and 350 MW. While for L3-1, most values are located at around -350 MW, meaning that power is flowing into node 3 most of the time. All values fall well inside the acceptable line limit which is set at 1350 MW.

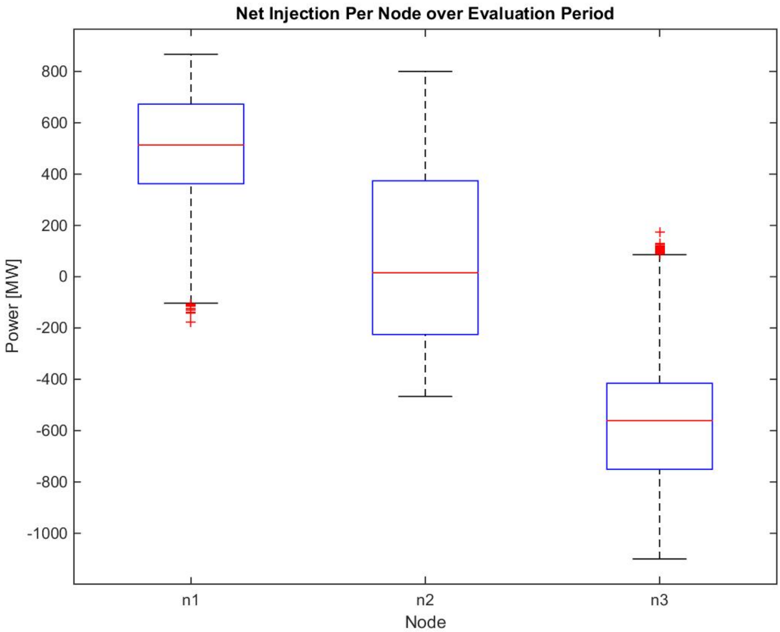

fig. 6.12. Box plot analysis of net injection at transmission system nodes.

A similar type of analysis is carried out regarding the values of net injection in each node. Net injection is the sum of all generation in the node plus incoming power flows minus demand and outgoing power flows. A positive value for net injection means that the node is exporting energy and a negative value importing. A zero value would mean that production and consumption are equal in the node. The results can be observed in figure 6.12. The results for net injection follow the same trend as the results of power flowing through the lines. The boxplot analysis shows that node 1 is the main exporter, and node 3 is the main importer, while node 2 falls in between. This occurs because node 1 has the least expensive generators, while node 3 has peaking units only dispatched during high load hours in the previous wholesale market results.

6.6.2 DSO's Request for Flexibility

The purpose of this analysis is to determine when the given schedule would be higher than the transformer capacity limits at the MV substation. This outcome provides the flexibility needed to solve a congestion problem at the DSO-TSO interface.

Illustrative examples with different scenarios of RES penetration are presented. Thre scenarios are presented, one without any renewable energy, the base scenario with scaled RES data from 2015 as explained before, and a high penetration RES scenario where the base case is scaled up to 200%. When there is more RES covering demand in the feeder, there is less need to use the transformer. Figure 6.13 presents the power profile that can be expected at the transformer across the year at three different cases of RES penetration. It is evident that when DG increases the power at the transformer decreases, because the biggest use of the transformer is to import power to the feeder. There is a point, where a big increase in RES penetration will lead to a case where transformer limits are crossed due to backflows. When the DRES production in the feeder is larger than the load this event might occur. Figure 6.14 represents a statistical analysis of the power profile throughout the whole evaluation period for every scenario. In the analysis, the top horizontal line represents the median of the observations. The box represents the values where 50% of the data fall and the upper and lower whiskers represent the top and bottom quartiles of data respectively. For the cases with low RES penetration, the peaks in load cause violations of the transformer limit. While for cases where there is a DRES increase of over 70% with respect to the base case, there are outliers that cross the lower bound of the transformer. Every instance where power is outside of the bounds of the transformer limit causes a need for flexibility.

The DSO can use flexibility in order to solve congestion problems at the transmission interface. Figure 6.15 outlines the DSO's power profile at the transformer under different scenarios. Following the results outlined in the previous section, for the base case and the case without DRES the DSO's need is for downward flexibility since the power is trespassing the upper bound of the transformer. However, as RES grows also upward flexibility will be needed to compensate for backflows that arise as can be observed in fig. 6.14. RES scenarios are presented to illustrate the possibilities of the methodology. In the results that follow the base case is analyzed.

6.7 DSO's Local Market: Results for Investment versus Flexibility Decision

The DSO has a need for flexibility that can be fulfilled by either buying demand response or investing in grid reinforcement. The DSO makes requests for flexibility based on a congestion analysis. The cost of DR is assumed to be

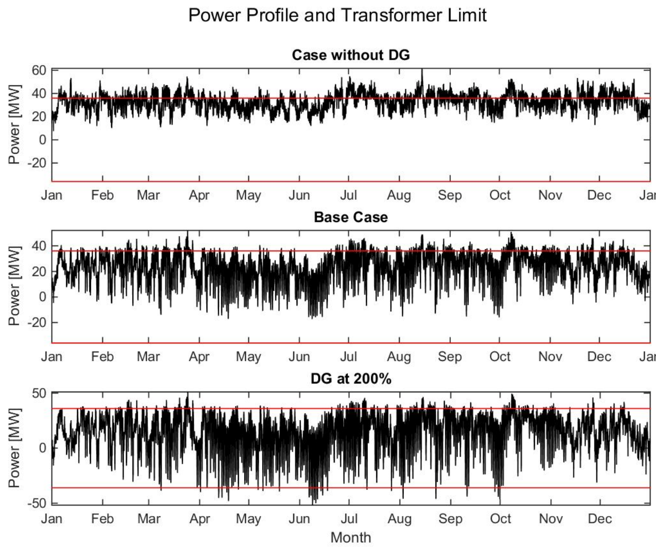

fig. 6.13. Resulting power profile at transformer and transformer limit during a year for a case without DRES (top), Base Case (center), and 200% RES (bottom).

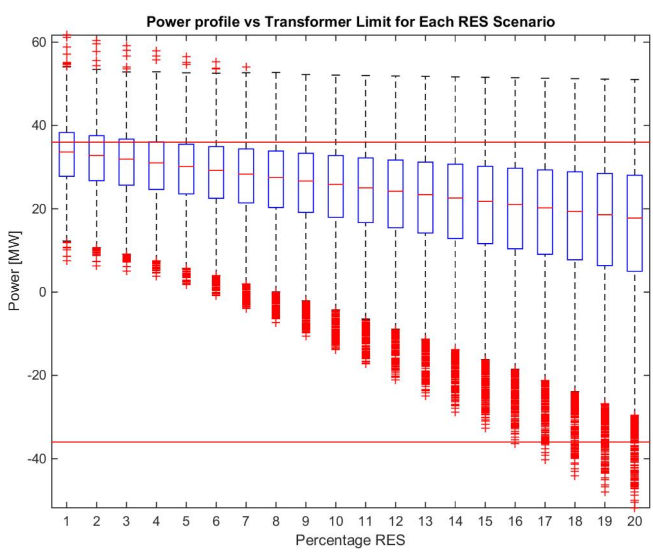

fig. 6.14. Statistical analysis of profile instances with respect to transformer limits for every scenario.

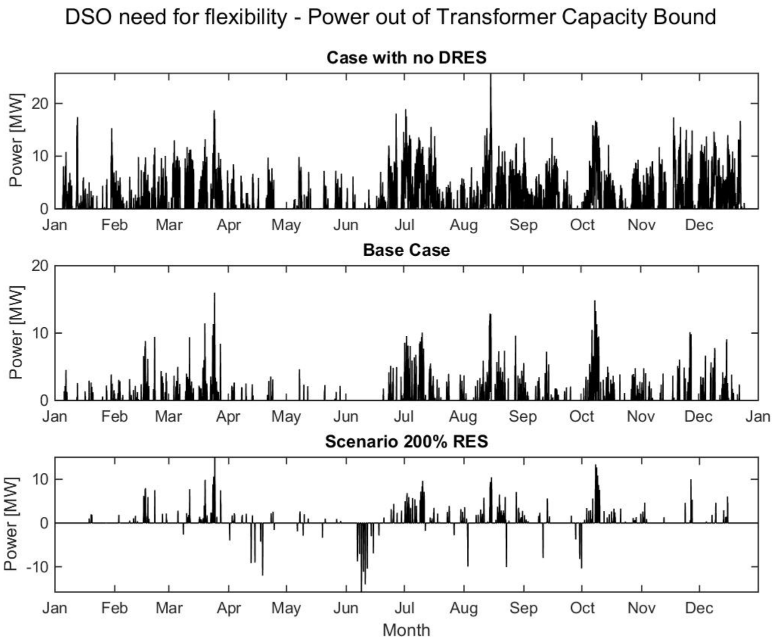

fig. 6.15. The DSO's need for flexibility in a case without RES (top), the base case (center), a case with 200% RES (bottom)

unknown to the DSO, but lying in the range of grid tariffs that consumers pay. Otherwise it would not make sense for them to participate in the local market.

The costs contained in the objective function are shown in figure 6.16. The DSO incurs a relatively low flexibility cost shown in the first bar. An expansion cost for the amount of flexibility that demand is not able to provide is shown in the second bar. The price benefit, shown in the third bar, that demand response creates for consumers is subtracted from the total costs.

The base case assumes a cost of DR of 40 €\MWh. Figure 6.17 presents the total costs that the DSO would incur if it used a combination of flexibility and grid investment in the first bar labeled 'With Flexibility' or in the absence of flexibility in the second bar labeled 'Without Flexibility'. In this scenario the DSO would save up to 66% in grid expansion. Cost concepts in the first bar are separated into the actual cost of flexibility and the cost of expansion. The cost of flexibility considers that the price benefit of demand response for the final consumer has been subtracted from it.

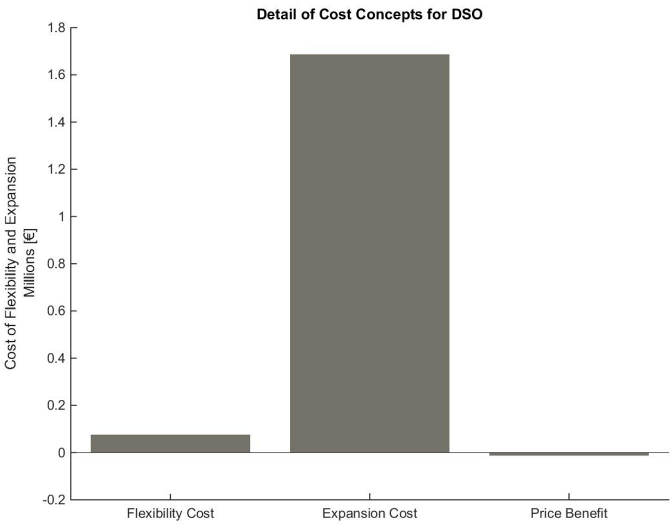

fig. 6.16. Cost concept detail for DSO for the evaluation period for the base case.

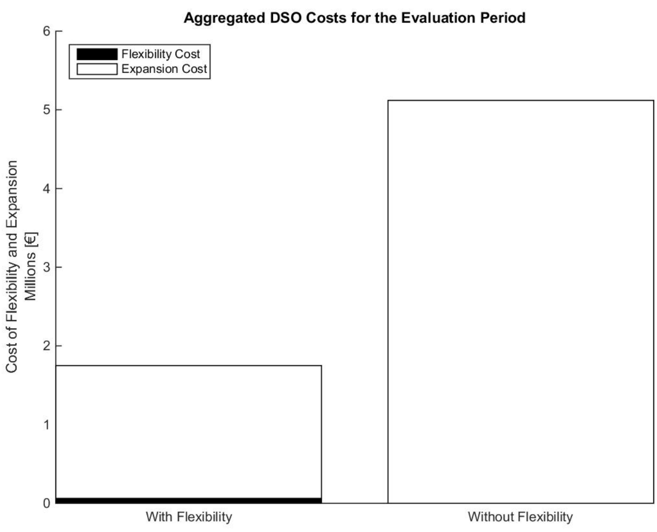

fig. 6.17. Aggregated DSO costs for the evaluation period for the base case.

The costs of flexibility for the DSO depend on the amount of demand response activated. The more demand response, the higher the price benefit for consumers, which decreases overall costs for the DSO. Figure 6.18 presents the total amount of upward and downward demand response activated during the whole year. The figure represents the sum of all flexibility dispatched, upward and downward for the entire year under each scenario. The upward flexibility dispatched is depicted as positive flexibility and the downward flexibility as negative. Four demand response cost scenarios are presented in the x-axis, 0, 15, 20 and 40 €\MWh respectively. Due to the shifting constraint total upward and downward activation values are equal for each scenario. Demand response is activated when the cost of demand response is lower than the price difference between peak and off-peak hours. In this case, the peak price for consumers is set at 50 €\MWh and the off-peak price at 30 €\MWh. The price difference in the presented case is then 20 €\MWh. It can be observed that demand response is used much more when it costs less than the price difference. This is due to the price benefit incurred through load shifting.

A sensitivity analysis to the cost of demand response of the total costs for the DSO using flexibility or not is shown in figure 6.19. As mentioned earlier, when the cost of demand response is less than 20 €\MWh, the price difference between peak and off-peak hours, a price benefit is incurred by consumers. Since the DSO pays only the cost of demand response above the benefit that consumers receive due to shifting, the first three scenarios generate a negative cost (profit) at 0, 5 and 15 €\MWh respectively. After that the DSO must compensate users or they would not be willing to offer demand response.

6.8 Conclusion

The DSO's demand for flexibility to solve grid congestion was determined qualitatively and quantitatively. The DSO needs to use flexibility when expected load flows would surpass transformer limits at the substations that connect transmission to distribution systems. In the analysis it is assumed that the rest of the network components are dimensioned according to transformer limits, but the same type of reasoning could apply to other components or performance indicators in the distribution network.

The value of flexibility for the DSO was studied. The price that the DSO is willing to pay for flexibility is capped by the cost it would incur if it decided to invest in grid expansion instead of buying flexibility. This constitutes the reservation price that the DSO is willing to pay for flexibility resources. The value is depicted by the white bar in figure 6.17, representing the total investment

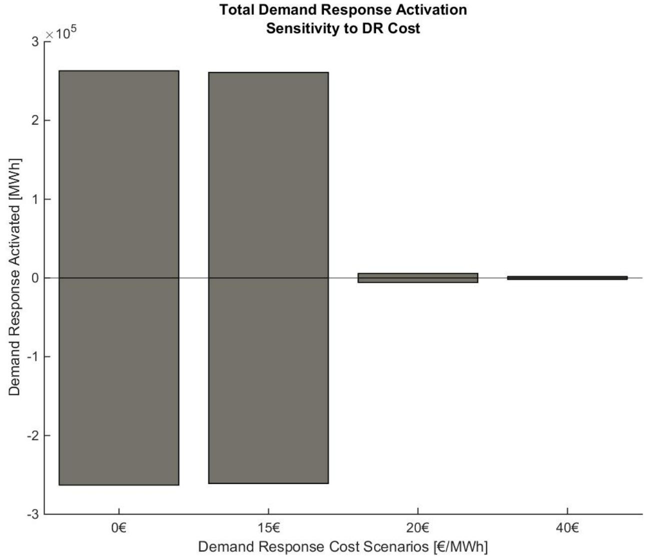

fig. 6.18. Total demand response activation during the evaluation period sensitivity to demand response cost scenarios, where 40 €\MWh is the reference case

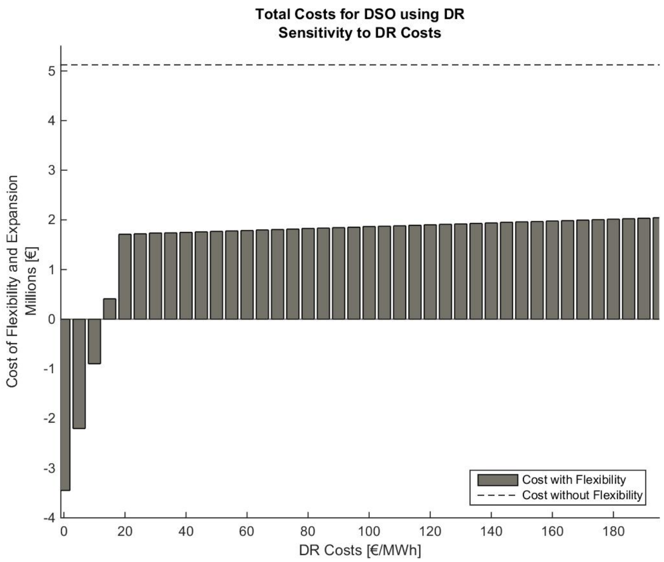

fig. 6.19. Sensitivity of total costs for DSO under different scenarios of DR costs with and without using flexibility.

in grid expansion that the DSO would face in the absence of demand response flexibility.

It was shown in the case study that the DSO can reap savings of up to 66% in total grid expansion through local flexibility contracting. The price-benefit of demand response is deducted from the cost that the DSO has to pay consumers as an incentive for offering the service. This price benefit is based on peak off-peak grid tariffs. It is profitable for consumers to offer demand response to the DSO as long as the internal cost of providing it is less than the price difference between the peak and off peak tariff. When their cost would be greater than that they would need an additional incentive to cover their costs and be motivated to offer demand response services to the DSO. Even when this would be the case it would still be profitable for the DSO to procure demand response to avoid grid reinforcements.

The time-frame for this type of decision-making for the DSO is long term. This is due to the time that it takes to reinforce the network in order to ensure the proper accommodation of RES. For the DSO, the methodology proposed can be used as a guide towards making a decision a year or months in advance on whether to build new lines or go into flexibility contracts.

The key element in this study is to create mechanisms that allow parties to access flexibility resources that do not currently participate in markets. This chapter presented a regulated market for reserves where the DSO buys flexibility resources at their cost value and is the only buyer of flexibility. In the following chapter a BRP who demands flexibility and a profit-maximizing aggregator are introduced.

Chapter 7

Local Competition for Flexibility

In this chapter a profit maximizing aggregator and a BRP are introduced. A simple representation of competition for flexibility between the DSO and the BRP is staged. In this chapter, the local market for flexibility is assumed to be bilateral, where the aggregator sells to the highest bidder.

A reasoning similar to chapter 6 is used in this chapter to define a quantity and a value that the BRP is willing to pay for flexibility. The BRP's need for flexibility is defined, also in the intraday horizon, based on differences between day-ahead RES forecast and real-time availability of resources. The value of flexibility for the BRP is given implicitly by the TSO through the imbalance prices that the BRP would incur if it does not settle its open position due to variations in the expected RES profile.

A profit maximizing aggregator decides who to allocate available flexibility to. The aggregator is subject to the transfer payment value mechanism proposed in the wholesale market and examined in chapter 4. The aggregator must make the decision of flexibility allocation well in advance of operation time because the DSO's need for flexibility is in the long-term. The aggregator must decide whether to sell flexibility to the DSO or keep it available for the BRP. The rebound effect is expected to occur, and the aggregator foresees enough flexibility capacity to comply with demand shifting within a 24 hour period. The focus of this chapter is to examine the competition for flexibility between the BRP and the DSO. Therefore, the effects of demand response on the BRP's profits are not described in detail once more.

The BRP's demand for flexibility is qualitatively described in section 7.1. The value of flexibility for the BRP is explained in section 7.2. The DSO's demand for flexibility is brought over from chapter 6 and paired with the BRP's demand in the aggregator's profit making decision in section 7.3. Input data to test the model is described in section 7.4. Results of flexibility allocation and profits for each party are presented in 7.5. Chapter conclusions are presented in section 7.6.

7.1 The BRP's Demand for flexibility

The BRP's need for flexibility is given by the difference between the day-ahead RES forecast and the actual RES availability in real time. Other deviations due to errors in load forecasting are not taken into account.

The change in RES profile is calculated by (7.1) to (7.3) as the difference between the real-time and the DA wind and PV profiles assuming perfect information.

$$\Delta Wind_t = RealW_t - DAW_t \tag{7.1}$$

$$\Delta PV_t = RealPV_t - DAPV_t \tag{7.2}$$

$$\Delta RES_t = \Delta Wind_t + \Delta PV_t \tag{7.3}$$

where

ΔRES	Change in renewable energy profile [MWh]
$RealW_t$	Real time wind generation [MWh]
DAW_t	Day-ahead wind generation forecast [MWh]
$RealPV_t$	Real time PV generation [MWh]
$DAPV_t$	Day-ahead PV generation forecast [MWh]

The BRP can have a positive (injection exceeds offtake) or a negative imbalance (offtake exceeds injection). A positive ΔRES means that there is a positive imbalance; and vice versa. The BRP needs flexibility as follows:

- Upward regulation: a need to buy energy in the form of downward demand response or an increase in generation. It is needed when there is a negative imbalance, ($\Delta RES_t < 0$).

$$BRPdowndr_t = \Delta RES_t \tag{7.4}$$

- Downward regulation: a need to sell energy in the form of upward demand response or a decrease in generation. It is needed when there is a positive imbalance ($\Delta RES_t > 0$).

$$BRPupdr_t = \Delta RES_t \tag{7.5}$$

7.2 Value of Flexibility for the BRP

Rationally, the BRP requires flexibility only when it incurs a penalty imbalance tariff, it has to pay the TSO for its imbalance. The nature of the imbalance tariff depends on the deviation of the entire system, and whether the BRP's specific time deviation helps or hinders the global network.

Changes in RES causes an imbalance depending on the direction of the change with respect to the forecasted amounts. The BRP must either compensate for these imbalances in the intraday market or face the imbalance tariffs placed by the TSO. For simplicity, it is assumed that the BRP values local flexibility at the value set by the TSO. This is because during moments of congestion, as given by the DSO, the BRP would not be able to trade those resources in the wholesale market.

A dual imbalance pricing method is assumed under the following conditions:

- When the BRP has a positive imbalance, where injection exceeds off-take, prices can be positive or negative:
  - Positive: payment from the TSO to the BRP.
  - Negative: payment from the BRP to the TSO.
- When the BRP has a negative imbalance, where off-take exceeds injection, prices can be positive or negative:
  - Positive price: payment from the BRP to the TSO.
  - Negative price: payment from the TSO to the BRP.

It is assumed that the BRP's reservation price for buying flexibility is the imbalance penalty itself minus a value to account for transaction costs of participating in the local market. The BRP only has a demand for flexibility when it will incur a penalty, meaning it has to pay money to the TSO due to its imbalance. In order to account for transaction costs of participating in the local market it is assumed that the BRP's reservation cost will be set at 80% of the imbalance penalty. Thus, the BRP will only buy flexibility in the real-time market when doing so is less expensive than paying the imbalance tariff.

7.3 The Aggregator's Decision

In this section it is assumed that the aggregator is the only supplier of flexibility in an area. All available flexibility is contracted and aggregated through this one party. The objective of the aggregator is in this case a profit maximization defined by (7.6). The aggregator is interested in selling to the highest bidder for flexibility at every time step so that its profits for the entire period are maximized.

A model where the aggregator decides between participation in reserves for transmission balancing and the day-ahead market is proposed in [190]. The author finds that the aggregator tends to participate in the reserves market more, and hedge price differences in the day-ahead market. Given that in this case the aggregator is deciding between selling to a DSO or a BRP the same reasoning applies with a few modifications. First, in [190] bidding is done for either the reserves market at TSO level or the wholesale market. In this section bidding is done for a local zone limited to a DSO feeder as described in chapter 6. The demand for flexibility for the DSO is given by the DSO's need for flexibility to relieve congestion. Second, in the model presented in [190] the need for reserves is given by system balancing needs coming from TSO data. In this section, the BRP is introduced as a market participant with an expected demand and a valuation for flexibility.

Perfect information is assumed about the reservation price of both the DSO and the BRP as explained earlier in this chapter. In addition, the aggregator must satisfy a shifting constraint, for which he also dispatches up and downward flexibility $qadjup_t$ and $qadjdown_t$. Continuing the proposals studied in the wholesale market, the aggregator will pay a transfer payment cost G to the BRP for all downward demand response. It is assumed that the aggregator only pays a transfer G for downward demand response dispatched, and is not responsible for the upward demand when consumers shift their load to a different hour.

$$\begin{aligned}
&\sum_t \{(qdsodown_t + qdsoup_t) * COSTDSO \\
&+ \sum_f (qbrpup_{t,f} * COSTBRPUP_{t,f} + qbrpdown_{t,f} * COSTBRPDWN_{t,f}) \\
&\qquad - (qdsodown_t + \sum_f qbrpdown_{t,f} + qadjdown_t) * G\} \qquad (7.6)
\end{aligned}$$

where

$qdsodown_t$ downward flexibility won by DSO at time t [MWh]

$qdsoup_t$ upward flexibility won by DSO at time t [MWh]

$qbrpup_{t,f}$ variable of upward flexibility won by BRP f at time t [MWh]

$qbrpdown_{t,f}$ variable of downward flexibility won by BRP f at time t [MWh]

$COSTDSO$ reservation cost of the DSO for flexibility purchasing [€\MWh]

$COSTBRPUP_{t,f}$ reservation cost of BRP f at time t for upward demand response [€\MWh]

$COSTBRPDWN_{t,f}$ reservation cost of BRP f at time t for downward demand response [€\MWh]

G transfer payment cost for agregator for providing demand downward demand response [€\MWh]

$qadjdown_t$ aggregator's need for downward demand adjustment at time t [MWh]

The aggregator's decision on flexibility allocation is constrained by the requested up and downward flexibility amounts of the DSO and BRP (7.7) to (7.10). BRP limits are absolute values of the BRP's demand for flexibility defined in section 7.1.

$$qdsodown_t \leq DSOdown_t \qquad \forall t \quad (7.7)$$

$$qdsoup_t \leq DSOup_t \qquad \forall t \quad (7.8)$$

$$qbrpdown_{f,t} \leq BRPdowndr_{f,t} \qquad \forall t \quad (7.9)$$

$$qbrpup_{f,t} \leq BRPupdr_{f,t} \qquad \forall t \quad (7.10)$$

The total amount of flexibility that the aggregator can provide is conditioned by (7.11) and (7.12). The same limit is used for both up and downward demand because only one of the two is dispatched in a certain time period. Binary variables u_t and v_t are used to ensure that only either upward or downward flexibility is offered at a certain period of time. This relationship is dictated by (7.13), where it is determined that only one of the binary variables can have a value of 1 at a certain time t. Finally, the aggregator must respect a demand shifting constraint within a subset of time t_s, usually 24 hours, (7.14).

$$qdsodown_t + \sum_f (qbrpdown_{f,t}) + qadjdown_t \leq AGGMAX_t * u_t \qquad \forall t \quad (7.11)$$

$$\sum_f (qbrpup_{f,t}) + qdsoup_t + qadjup_t \leq AGGMAX_t * v_t \qquad \forall t \quad (7.12)$$

$$u_t + v_t \leq 1 \qquad \forall t \quad (7.13)$$

$$\sum_{t_s} \{ \sum_f [qbrpup_{f,t} - qbrpdown_{f,t}] + qdsoup_t - qdsodown_t$$

$$+ qadjup_t - qagdjdown_t \} = 0 \qquad \forall t_s \quad (7.14)$$

7.4 Input Data

The data used in this simulation is taken from the analysis in chapter 6. The DSO's bidding criteria is modified to account for a price per MWh. The BRP's need for flexibility is described using forecasted and real time values for RES during 2015 in Belgium, scaled down to the feeder size as described in chapter 6.

7.4.1 The DSO's Need for Flexibility

In this case, the DSO's reservation price of using flexibility is the value defined in section 6.5.3 of grid expansion per MWh, 160 €\MWh calculated according to 6.9. Similar to the BRP's reservation cost, this value is reduced by 20% to account for transaction costs and risk management. Thus, the value used in the simulations is 128 €\MWh.

7.4.2 The BRP's need for Flexibilty

As explained in section 7.1 the BRP's need for flexibility is given by the difference between the day-ahead RES forecast and the actual RES availability in real time. In the simulations it is assumed that the BRP's need for flexibility is

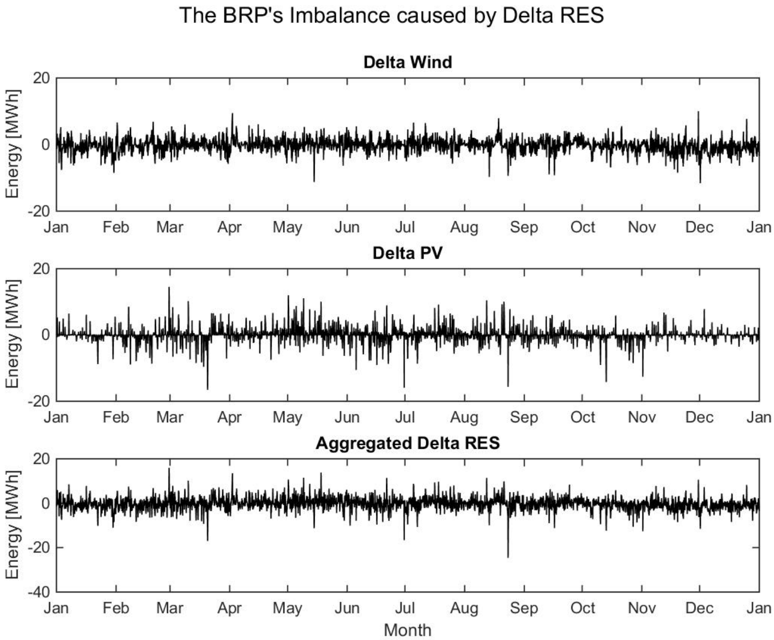

fig. 7.1. The BRPs need for flexibility is given by changes in the expected RES profile, $\Delta WIND$ (top), ΔPV (center) and combined ΔRES (bottom). Data is scaled based on RES production in Belgium during 2015.

known at the time of the local market clearing. As mentioned earlier, the BRP can have a positive (injection exceeds offtake) or a negative imbalance (offtake exceeds injection). Input values used in the base case can be observed in figure 7.1 and are based on forecasted and measured RES production values for Belgium during 2015.

Rationally, the BRP will require flexibility only when it incurs a penalty imbalance tariff. The BRP requires flexibility when it would have to pay the TSO for its imbalance. The nature of the imbalance tariff depends on the deviation of the entire system, and whether the BRP's specific time deviation helps or hinders the network. This data is assumed to be input, and perfectly known in advance based on the imbalance tariffs in Belgium during 2015. It is also assumed that the BRP's reservation price for buying flexibility is the imbalance penalty itself. Thus, the BRP will only buy flexibility in the real-time market when doing so is less costly than paying the imbalance tariff.

Figure 7.2 represents the need for flexibility which is given by the imbalance

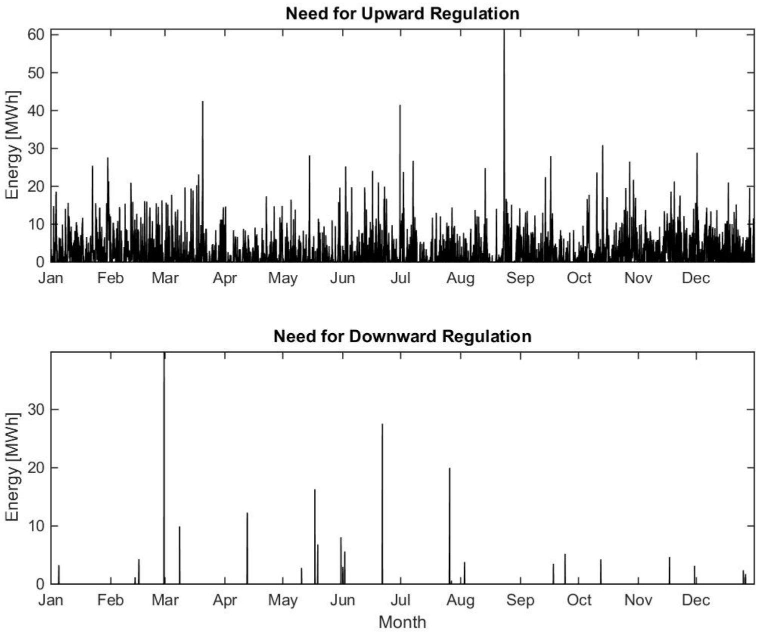

fig. 7.2. The BRPs need for flexibility expressed as needed upward regulation (top), and downward regulation (bottom).

caused by changes in RES. As outlined in section 7.1 the BRP will need flexibility as follows:

- Upward regulation: needed when there is a negative imbalance, meaning that $\Delta RES < 0$.
- Downward regulation: needed when there is a positive imbalance, meaning that $\Delta RES > 0$.

Figure 7.3 presents the imbalance price that BRP would have to pay to the TSO in the absence of corrective actions. This value becomes the reservation price for flexibility, for upward regulation (top), and for downward regulation (bottom). In this case, the BRP is only a buyer of flexibility in order to demonstrate a simple case of how it would compete for flexibility against the DSO. Other cases can be envisaged in future research where the BRP also provides flexibility in the local market from its own portfolio.

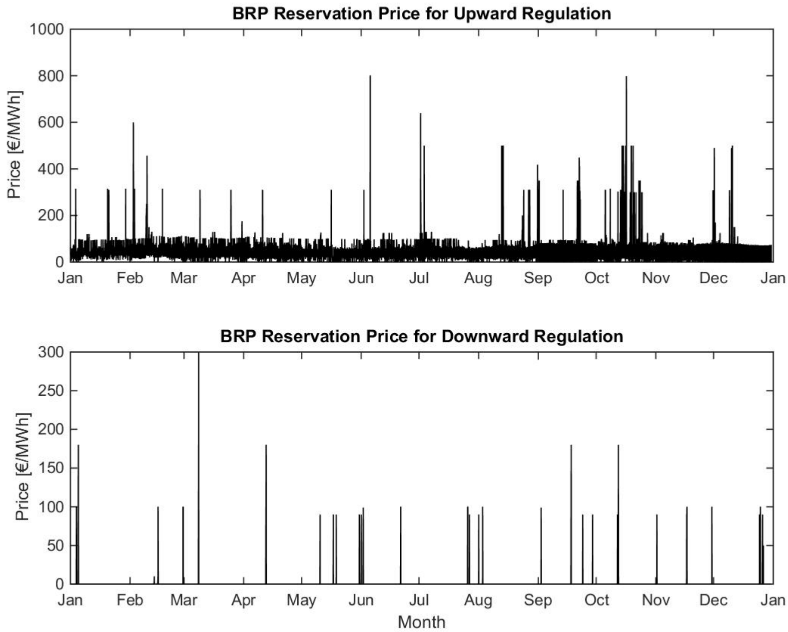

fig. 7.3. The imbalance price for upward regulation (top), and for downward regulation (bottom).

7.5 Results of Aggregator's Decision

As a commercial actor the aggregator aims to maximize profits in the local market. The available demand response is sold to the highest bidder at each actor's bid price. The base case is defined at at DR transfer price of 40 €\MWh. Figure 7.4 shows the allocated amount of downward demand response for the BRP (top) and the DSO (Bottom) over the year. The aggregator must dispatch flexibility to compensate the shifting constraint as depicted in figure 7.5. Upward demand response is displayed as positive values and downward as negative ones. All of the DSO's initial request is for downward flexibility, and most of the BRP's also, therefore the aggregator dispatches mostly upward demand response to compensate. In this scenario the DSO wins 89% of it's bid and the BRP wins 60% of it's bid. Several time periods can be observed when both the DSO and the BRP have a high request for flexibility at the same time. When this is the case the highest bidder will win the available flexibility since the aggregator is looking to maximize profits. The reservation cost of the DSO is fixed at 128

€\MWh and the BRP's cost is variable through time, as can be observed in figure 7.6.

For the DSO the cost of managing the congestion encountered in the network is equal to the cost of purchasing flexibility plus the cost of grid reinforcements where flexibility is not estimated to be available. Figure 7.7 compares the costs of covering the grid congestion through either flexibility contracting (the left bar) or through grid reinforcements (right bar). It can be observed that costs can be reduced by 10% for the DSO. The new costs for the DSO as calculated by adding the total cost of buying flexibility in the market, plus the cost of investing in grid expansion to cover the remaining peak that the aggregator cannot offer. In this case, compared to the case without competition, the DSO wins less flexibility use and therefore has higher costs.

A similar calculation is done for the BRP, where the cost of covering part of the imbalance through available flexibility is compared to the cost of paying the imbalance price. Figure 7.8 represents the costs that the BRP would have to pay if part of the imbalance is solved through the local market (left bar), or what the BRP would have to pay to the TSO otherwise. The BRP's costs decrease by 17% when flexibility is used.

Figure 7.9 represents the aggregator profits' sensitivity to different transfer payment values. Each bar represents the profits the aggregator makes over the entire evaluation period. Thus, each bar is one run of the model. The top chart presents the selected scenarios that were discussed in chapter 4, at 0, 30 and 45 €\MWh. It can be observed, that in contrast to chapter 4, the aggregator reaps a profit even at the higher proposed value for the transfer payment at 45 €\MWh. In the bottom chart, more scenarios are introduced in order to assess the aggregator's profits under more scenarios of transfer payment values. It can be observed that at the point where the DSO is no longer willing to pay for flexibility, 128 €\MWh in this case, the aggregator still makes a profit since the BRP has at times a higher willingness to pay given by the imbalance penalties it would incur if it doesn't buy flexibility.

Figure 7.10 shows the total amount of flexibility dispatched for each scenario of transfer pricing. The DSO wins flexibility in every case until the transfer payment surpasses its willingness to pay at 128 €\MWh. The BRP is more affected by transfer payment values, and wins considerably less bids after the transfer payment value is above 80 €\MWh. Nevertheless, given that the BRP's willingness to pay varies over time, there are peaks in the bidding price and therefore the BRP still wins a small amount of flexibility even at higher transfer pricing scenarios for the aggregator. The aggregator must always balance out the bids allocated in order to satisfy the shifting constraint, therefore, the aggregator dispatches an amount of flexibility equal to the sum of the BRP and

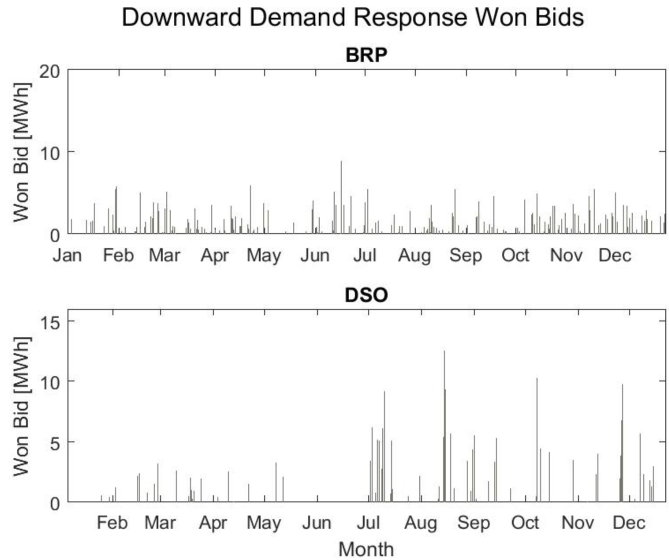

fig. 7.4. Allocation of downward demand response flexibility or upward regulation, for the BRP (top), for the DSO (Bottom).

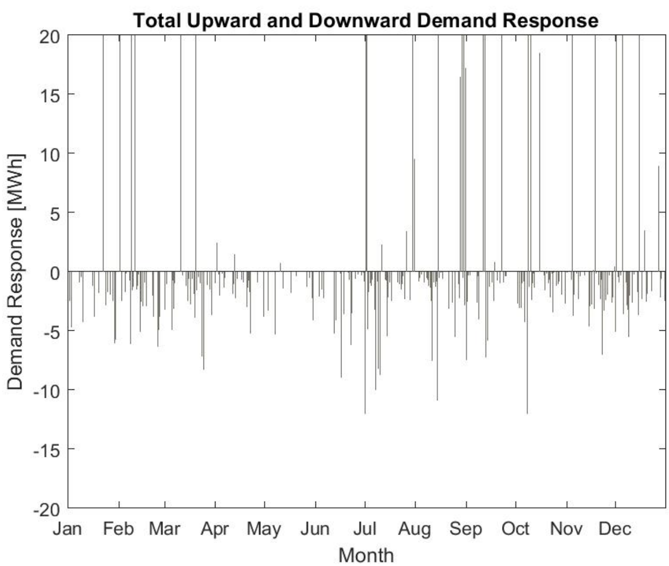

fig. 7.5. Total demand response including additional flexibility needed by aggregator to satisfy demand shifting constraint.

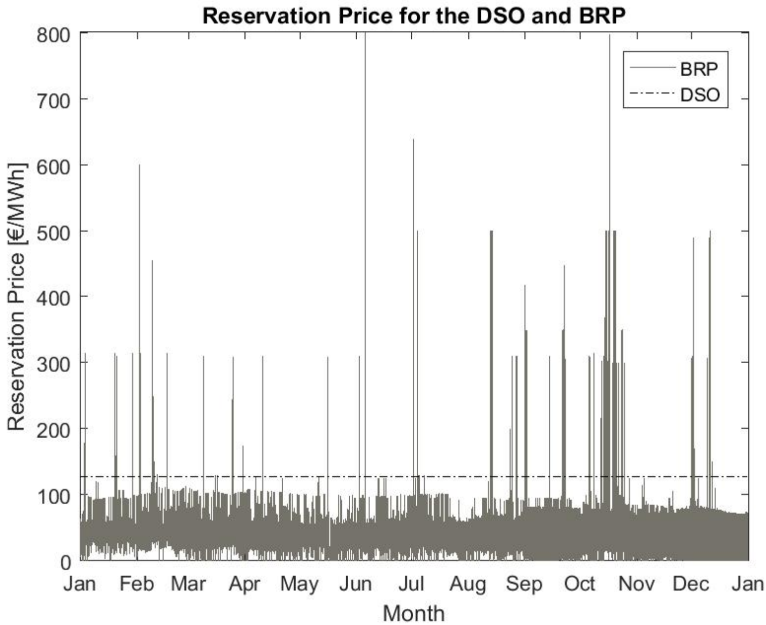

fig. 7.6. Reservation price of BRP versus DSO

the DSO's won bids.

Figure 7.11 represents the total flexibility allocated to the DSO with respect to the initial requested bid. For the selected scenarios of 0, 30, and 45 €\MWh the DSO wins almost its entire requested bid, as depicted in the top of the figure. The DSO continues to win almost its entire bid up until the transfer price is equal to the DSO's willingness to pay. After that point, the DSO does not win any bid at all.

Figure 7.12 depicts the same concept of flexibility allocation for the BRP as was presented for the DSO. In the selected scenarios, observed in the top half of the figure, the BRP sees a decrease in it's bidding fulfillment since it's willingness to pay varies over time and is sometimes lower than the selected transfer payment values. In the third scenario, at 45 €\MWh transfer price only 62% of its bid is fulfilled, compared to 98% in the absence of a transfer price. In the extended scenarios it can be observed that the BRP's won bids diminish significantly when the transfer payment values increase. After the transfer payment value reaches 80 €\MWh less than 10% of the BRP's bid is fulfilled.

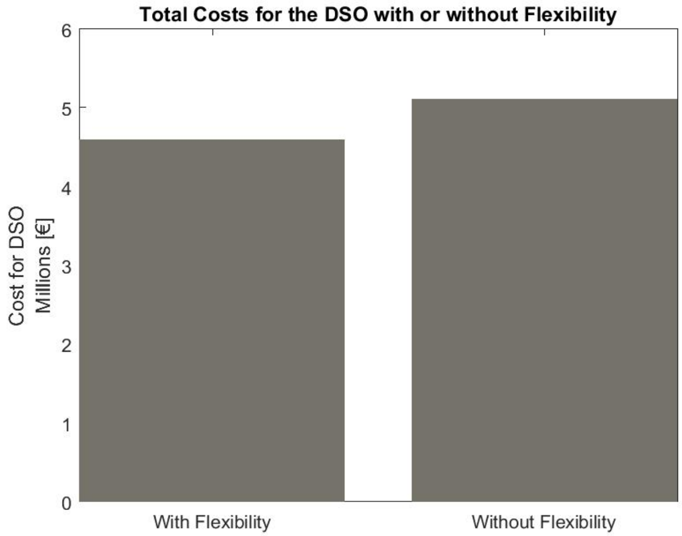

fig. 7.7. Costs for the DSO of congestion management with or without flexibility during the evaluation period

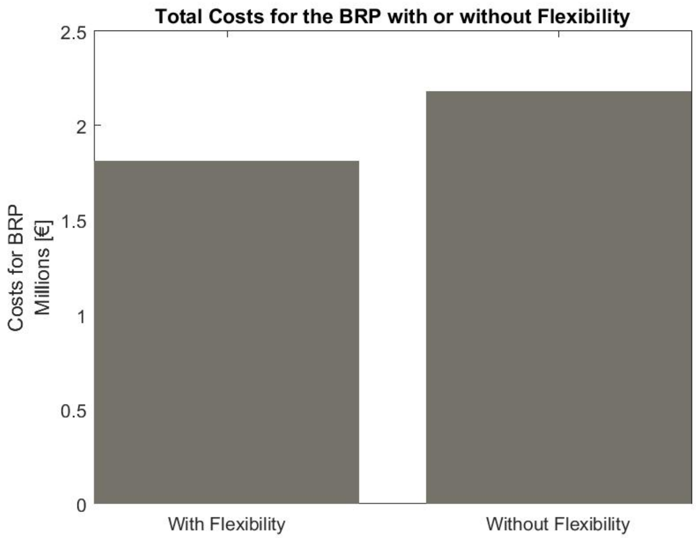

fig. 7.8. Costs for the BRP of imbalance management with or without flexibility during the evaluation period.

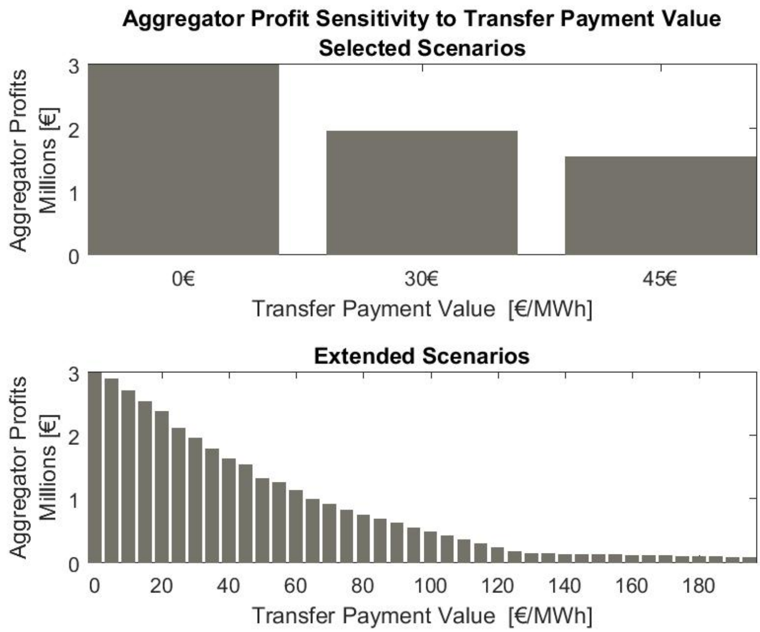

fig. 7.9. Aggregator profits sensitivity to transfer payment value, selected scenarios (top), extended scenarios (bottom)

7.6 Conclusion

The aggregator is introduced as a profit maximizer who decides to sell to the highest bidder. In this setting, the DSO competes with the BRP for demand response resources. The modeling illustrates the decision making process that the aggregator undertakes in order to decide whether to provide flexibility to the DSO, in advance, or keep it available for the BRP. Flexibility for the DSO must be reserved in advance since the DSO's decision is a long-term one.

This chapter presented a case where one aggregator is the sole supplier of flexibility. Given this scenario the aggregator is likely to set monopoly prices in the absence of competition on the supply side. The simple case is representative of the rationality of the actors, but an extension of the case to include competition on the supply side would contribute insights to the discussion. The setting is tested under the proposed transfer payment schemes discussed in the previous chapters. The transfer payment means that the aggregator has to pay the BRP (or retailer) of consumers providing demand response, for all downward demand response provided.

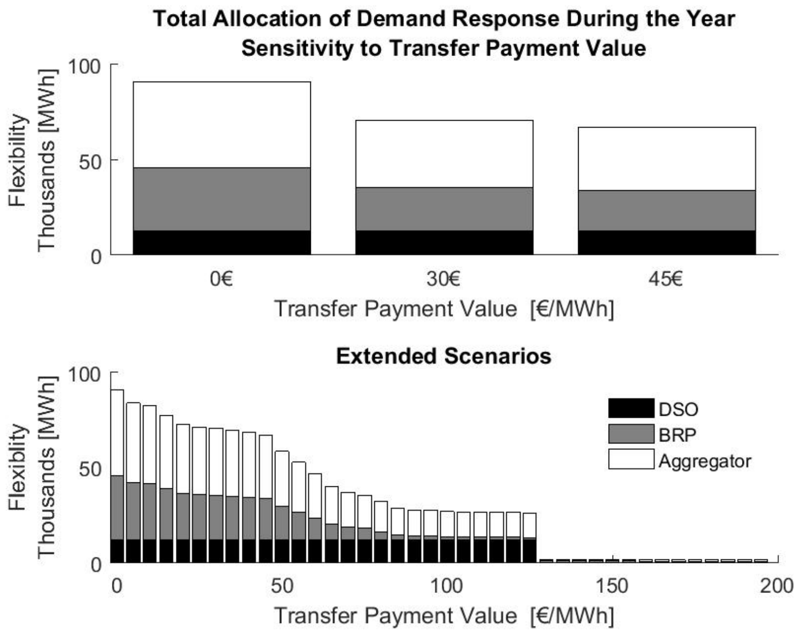

fig. 7.10. Total amount of demand response dispatched per BRP, DSO and aggregator for selected scenarios of transfer pricing, in both upward and downward directions (top) and for extended scenarios (bottom)

In the base case, where the transfer payment is equal to 40 €\MWh it is shown that the aggregator chooses to fulfill all of the DSO's bid first, as long as the shifting constraint is maintained, while fulfilling only 64% of the BRP's bid. This is because the DSO's willingness to pay is at a constant of 128 €\MWh, while the BRP's willingness varies depending on balancing fees set by the TSO and is generally lower than the DSO's. In a sensitivity analysis of different possible transfer payment prices, it is shown that up to the DSO's limit reservation price, the DSO wins almost all of it's bid.

In all cases the aggregator maintains a positive business case, even when it's profits logically decrease with higher transfer payment values. This is different from the case shown in the wholesale market, where at transfer payments higher than 20 €\MWh, the aggregator did not make a profit any more. Overall, given transfer payment rules, the aggregator prefers to sell flexibility to the DSO, when needed. The remainder of the available flexibility is sold to the BRP. It is preferable for the aggregator to sell to the BRP in the local market rather than the wholesale market.

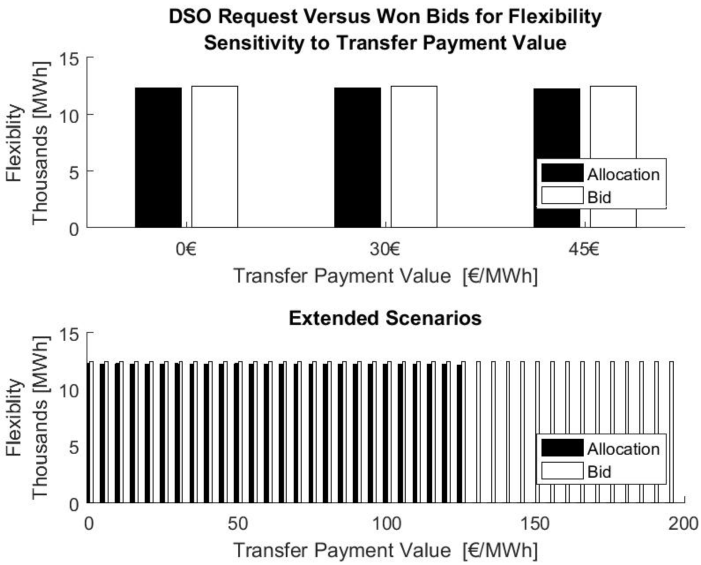

fig. 7.11. DSO Bid Request Versus won Bids Sensitivity to Transfer Payment Value for selected scenarios (top) and for extended scenarios (bottom)

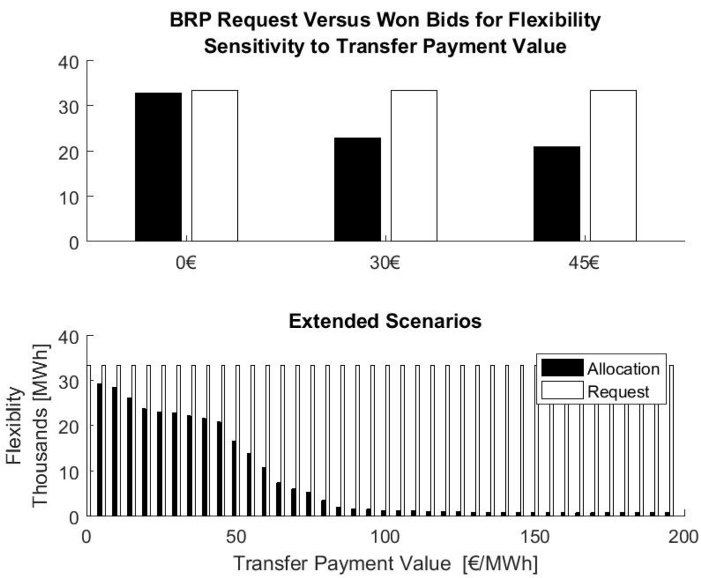

fig. 7.12. BRP Bid Request Versus won Bids Sensitivity to Transfer Payment Value for selected scenarios (top) and for extended scenarios (bottom)

Chapter 8

General Conclusions

This chapter summarizes the main discussions and findings of this thesis in section 8.1. The conclusions are presented based on the research questions posed in chapter 1. Opportunities for future research are presented in section 8.2.

8.1 Answers to Research Questions

Faced with growing RES penetration flexibility has become a commodity that many parties can profit from in different ways. Flexibility, in the form of system and market flexibility, provides a solution to growing problems due to the introduction of RES. These problems include grid concerns such as congestion and voltage stability as well as commercial concerns related to the interactions between stakeholders and the use of limited resources. Markets for flexibility arise in order to cover the need caused by variability and unpredictability of RES. It was identified that flexibility can be used for varying purposes at different levels of the grid. The main findings of the thesis are described below by answering the research questions proposed in chapter 1. Part I analyzed the integration of flexibility into the wholesale market while Part II studied the use of flexibility at a local level.

8.1.1 Part I

How is aggregated demand response integrated into the wholesale market?

In order to study possible mechanisms of contracting flexibility key aspects of electricity market design were distilled from the literature. The main dimensions of trading identified were:

- Temporal: relating to the timing of contracting, whether it be long or short- term.
- Market clearing and price formation: resources could be remunerated under a pay-as-bid or a pay-as-cleared marginal pricing scheme.
- Spatial: relating to the geographical area for which electricity is contracted and prices are settled.
- Contractual: relating to the way in which agents engage in trade among each other. The most common being bilateral contracting and power exchanges.

Demand response was placed within a reference day-ahead wholesale market design using the characteristics presented above. This thesis considers explicit demand response, where consumers receive direct incentives to modify their consumption patterns. As such, demand response bids into the wholesale market alongside generators of electricity. Proposed mechanisms for remunerating demand response were studied. One main variant argues that demand response should receive the full marginal price for providing a service to the market equivalent to that of generation. Another variant argues that the savings achieved by the consumer for providing demand reductions should be enough motivation for demand to change its consumption patterns according to price signals. The notion of transfer pricing is proposed where a value, G, equivalent to the cost of sourcing the demand reductions is subtracted from the full marginal price. This scheme is named MP-G. Prominent markets like PJM adopted a full marginal price approach, while other markets like EPEX spot in France and ERCOT in Texas adopted variations of the MP-G approach. Most discussions in literature talk about demand reductions only, and neglect that consumers will most likely increase their consumption at a later hour after a demand response event. The effect of demand shifting was not taken into account in the discussions. The effects of demand response on the market and on other market participants were analyzed next.

What is the effect of the participation of aggregated demand response in the wholesale market?

The rebound effect is key to analyzing the effect of demand response on the wholesale market transactions. The rebound effect is defined as the shifting of load from a high price hour to a lower price hour due to actions of demand response initiated by a consumer or by an aggregator at the consumer's site. If optimally placed, the rebound means that consumers will observe a price benefit of demand response by shifting consumption from high price hours to low priced ones.

When demand response is initiated by a third party aggregator, the consumer's retailer is affected by actions over which it doesn't have control. Given the rebound effect it was concluded that demand response has an effect on the BRP's portfolio:

- Market Effect: if the BRP has sent a schedule of supply and demand that will be affected by third-party aggregator actions, an imbalance in the DA-market is expected for the BRP. The BRP's profits are affected in different ways depending on whether the BRP has information about the aggregator's actions in advance or not as follows:
  - BRP observes aggregator's actions prior to the market: in this case the BRP can solve its long or short positions in the market itself.
  - BRP doesn't observe the aggregator's actions: if an imbalance is created, and not solved through market actions at day-ahead or intraday level, there will be an imbalance price for not complying with the proposed production and consumption schedules.
- Retail Effect: the BRP's profits depend partly on the retail contracts in place. If actions by the aggregator will change consumer's behavior this will also have an impact on the expected retail profit. This effect will occur in both scenarios of information on the market effect for the BRP.

How are the costs and benefits of demand response in the wholesale market allocated among market participants?

Proposals for dealing with the effects of demand response were analyzed. The solutions vary according to the attribution of balancing responsibility to the aggregator, the BRP, or a sharing of responsibility through adjustments of the open positions caused by demand response actions. The main trends identified are:

- Day-Ahead market effect: if the BRP has sent a schedule of supply and demand that will be affected by third-party aggregator actions, an imbalance in the DA-market is expected for the BRP. The BRP's profits are affected in different ways depending on whether the BRP has information about the aggregator's actions in advance or not as follows:
  - The BRP observes the actions of the aggregator before the day-ahead wholesale market under the following settlement mechanisms:
    - Full MP: The BRP has balancing responsibility and covers the imbalanced position at the market Marginal Price. The aggregator receives the full MP.
    - MP-G: The Aggregator has balancing responsibility and covers the imbalanced position at a regulated price G representative of the sourcing costs of the energy sold as demand response.
  - The BRP does not observe the actions of the aggregator and the BRP's imbalanced position is left open. The attribution of this imbalance is studied in chapter 4 as follows:
    - The imbalance is attributed to the BRP.
    - The imbalance is attributed to the Aggregator.
    - The imbalance is neutralized by the system operator and its costs are socialized.
- Retail Effect: the BRP's profits depend partly on the retail contracts in place. If actions by the aggregator will change consumer's behavior this will also have an impact on the expected retail profit. This effect will occur in both scenarios of information on the market effect for the BRP.

A dynamic model to analyze the effects and proposals is introduced. The model represents the optimal dispatch that would be expected in a wholesale market taking into account demand response availability. BRPs that own a portfolio of generation and load are introduced. BRPs must be in balance through either the use of own resources or purchases and sales from other BRPs or the aggregator. The aggregator is remunerated only for downward demand response for simplicity. The rebound is assumed to occur at the best possible moment. Scenarios of demand response remuneration are tried out varying between remuneration at the full MP, and remuneration at MP-G. Two different values of G are initially tested, 30€\MWh and 45€\MWh. A sensitivity analysis of different values of G from 0 €\MWh to 100 €\MWh is also done.

Results show that demand response substitutes peaking generation. Demand response has two effects on the profits of the BRP. There is a market and a retail effect. On the market side, the BRPs who own the peaking generators earn less on sales, but they benefit from buying cheaper energy to cover their load portfolios on the retail side. It is shown that the sum of net market and retail effects for the BRP is positive over the evaluation period. This is because demand response has an arbitraging effect with respect to market price differences. In the case where the aggregator pays a transfer value, the BRP also receives this price on top of the price benefit of demand response due to arbitrage. In these cases, though, much less demand response is dispatched.

When the BRP does not observe the actions of the aggregator its position is left open. There is a discrepancy between its nominations of load and generation to the system operator and the actual off-take and injections of the users within the BRP's perimeter. When the position of the BRP would be left open due to the actions of the aggregator it would incur an imbalance. This is the imbalance effect of demand response. Prices for positive and negative imbalances are given by system conditions and set by the TSO. In the model they are input values. With the values used, the activation of demand response generally helps the system. Three proposals for the imbalance allocation are proposed: the BRP covers the imbalance, the aggregator covers the imbalance, or the system operator absorbs the imbalance and socializes the costs. The results show that the party responsible gains in the imbalance market in the presence of demand response.

The retail effect for the BRP is caused by a loss of tariff income at a time of demand reduction and an increase at a time of demand rebound. The transfer payment affects the total amount of demand response dispatched, thus indirectly affecting also the retail income of the BRP. Intuitively, it was deducted that the retail effect would cause a loss for the BRP, however, in the simulations the result was the opposite. This happened due to two main reasons. The first is that a shifting horizon of 24 hours was applied to demand response. Therefore the shifting sometimes occurs at times of intermediate price hours. The second is that the peak and off-peak tariff regime does not accurately represent the price peaks and valleys observed in the wholesale market. An aggregator optimizing sales of consumer flexibility, and making decisions based on wholesale market prices, might not always act in the best interest of the consumer.

The effect on the market itself is given by the total costs of running the market with or without demand response. Savings of about 6 % of the total costs are achieved with an available demand response flexibility equivalent to 5% of the peak load. With the introduction of transfer pricing at 30€\MWh the expected savings are cut by more than 50%.

The aggregator's profits suffer significantly with the introduction of transfer pricing when it is being remunerated for downward demand response at the market price for energy. In the model when the transfer payment of the aggregator is higher than 20 €\MWh the aggregator makes a loss. At this point a rational aggregator would no longer participate in the market and the benefit of demand response would be lost.

It can be argued that the market savings achieved are only a transference of wealth from the peaking generators to the consumers. Nevertheless, when peaking generators are not needed due to demand reductions society as a whole uses less resources. When demand reduction would be created through the use of in-house generation, for example, then it can be said that there is a transference of wealth from peaking generators to demand response providers. Gains for society are created when existing, more efficient, plants are used more often through load curve flattening.

Market flexibility is key to facilitate the integration of RES given its variability and limited predictability. Allowing the aggregation role to participate in the market on equal terms as other generation enables the growth of flexibility supply. This flexibility supply ought to come from resources that previously were not able to reach and respond to market signals. These are resources such as aggregated household consumers, small businesses, and even small DER not having the expertise to bid in markets. When new participants respond to the market, available resources can be used more efficiently, creating gains for society. The thesis goes on to study the relationship between the decisions taken in the wholesale market and the network at different voltage levels in order to determine when and how a local market could be organized.

8.1.2 Part II

Why is a local market necessary?

A local market is necessary when distributed renewable energy resources causes disturbances in the local distribution grid. The issue of grid congestion at the distribution-transmission interface is analyzed in particular. When congestion occurs in the grid during a limited amount of hours per year, it is more cost efficient to manage it through the use of flexibility than through the conventional solution of reinforcing the grid. Throughout the last two decades there have been variations of proposals to deal with local grid issues, such as microgrids, technical virtual power plants and commercial virtual power plants. The definition of a local market is set by the purpose of using the flexibility either for system services or for commercial purposes. These concepts were initially location specific, but later grew to encompass financial transactions for flexibility that might be located in different areas. The market design in place defines how stakeholders interact with each other with respect to the use of flexibility. After studying the evolution of concepts related to local flexibility contracting this thesis arrived at the following definition of local market:

Local Market: Long- or short-term trading actions for flexibility in a specific geographical location, voltage level and system operator (DSO and TSO), given by grid conditions or balancing needs, where participants in a relevant market can be aggregated to provide flexibility services.

How can a local market for flexibility be organized?

Given that the market participants include commercial parties such as the BRP and the aggregator, as well as regulated parties such as the DSO and the TSO there is a need for flexibility contracting structures that cover the needs of every participant. Current market design proposals were analyzed and it was clear that there is a lack of consensus regarding who should take up the role of flexibility market operator as evidenced in chapter 5. The DSO, the TSO, and an independent party have all been designated as flexibility market operators in different proposals. Main approaches for flexibility contracting as identified in the literature were outlined and described through the characteristics of market design identified previously:

- Local Reserves market: single buyer market, open to competition only on the supply side. It is assumed that the single buyer is a regulated actor, one of the system operators. Two main variants arise:
  - DSO-priority in flexibility contracting.
  - TSO-priority in flexibility contracting.
- Local competition for flexibility: a market open to competition on supply and demand.

The thesis focuses on analyzing DSO-priority in flexibility contracting, given that at the very local level the DSO needs to determine when there is a need for flexibility. The topic of TSO-priority in local flexibility contracting, while also relevant, is out of the scope of the rest of the thesis. It is the DSO who will be impacted by growth in RES and would have to either actively manage the network or reinforce it.

What is the local need for flexibility and what is its value?

The need for local flexibility is given by grid congestion conditions at the transmission distribution interface. It is defined by the expected power flows above transformer substation limits in a specific feeder. Two main cases are defined for either downward or upward flexibility depending on grid conditions. Downward flexibility is needed when expected power flows would surpass substation limits. In this case a demand reduction would help the system to relieve congestion. Upward flexibility is needed when too much renewable energy is expected in the feeder and powerflows would be reversed and above substation limits. In this case an increase in demand would help the system to relieve congestion.

A methodology to determine the need for flexibility is proposed based on a power flow analysis. Current and voltage values resulting from the power flow are converted to active power and reactive power. Active power above transformer limits constitutes the DSOs need for either flexibility or grid reinforcements. Thus, the value of flexibility for the DSO is equivalent to the savings achieved in grid reinforcements through flexibility contracting.

How can a DSO-led reserves market for flexibility be organized?

The case of a DSO-led market is proposed through a decision making model where the DSO decides whether to buy flexibility at cost value or invest in grid reinforcements. The cost value of flexibility is treated as an unknown parameter as it varies significantly according to the type of consumer providing flexibility. It is assumed that the DSO is buying directly from consumers. In turn, consumers receive a price benefit of offering demand response coming from the difference in price hours between demand reduction and demand increase. This price benefit is subtracted from the cost value that the DSO has to pay consumers for providing flexibility. It is shown in the results that the DSO can save up to 66% in the value of grid reinforcements through purchasing flexibility in this way. Consumers are motivated to offer flexibility as long as their internal cost of providing it is less than the price difference between the peak and off-peak tariffs that they face. If their cost increases, it is not longer profitable to offer services to the DSO without additional remuneration.

If the DSO competes for flexibility with the BRP, who is better off?

The case of a competitive market for local flexibility is introduced through a model where a profit maximizing aggregator decides whether to sell it's available flexibility to the DSO or a BRP. The BRP's need for flexibility is defined by the change in renewable energy forecasts to the real-time availability. The value of flexibility for the BRP is equal to the penalty it would face for being imbalanced as set by the system's imbalance prices set by the TSO. Both the DSO and the BRP decide to bid in the local market at 80% of their defined reservation costs in order to account for unknown transaction costs of participation.

The aggregator once more faces possible transfer payments to the BRP which affects its profits. In this setting though, both parties are willing to pay more than the wholesale market price. The aggregator continues to make a profit even with higher transfer payment values. A sensitivity is done regarding the transfer payment values and the willingness of the aggregator to offer flexiblity under increasing costs of provision.

In the study the DSO wins his bid in every case right up until the aggregator's transfer payment is higher than its reservation cost. The BRP wins only about 40% of its bid in the base case where the aggregator faces a transfer payment of 40 €\MWh. This occurs because the BRP's willingness to pay for flexibility is on average lower than the DSO's, with some exceptions when imbalance prices tend to have peaks. This situation could change, though, as it depends on the imbalance prices set by the TSO as given by grid conditions.

The tool presented is an indicative planning tool for the aggregator. Since the DSO needs to make a decision at the beginning of an evaluation period, the aggregator needs to decide then whether to sell to the DSO or keep it available for the BRP who requires it in real time.

The market mechanisms used to contract flexibility ought to accommodate the full exploitation of the flexibility potential. Electricity market design aims to promote competition and free access to resources. Therefore market design rules should allow parties to compete for flexibility resources. In this work it is proposed that the party who values flexibility the most is the one who ought to use it, even when different purposes are intended.

8.2 Future Research

This work focuses on proposing a methodology to implement a local flexibility market. However, the optimal size of the local market is yet to be determined. It has been proven in literature that flexibility on a residential feeder level can improve grid operation. It remains to be seen if the transaction costs of organizing such small markets are worth the effort.

In this thesis mainly the economic local issues arising from the introduction of DER are taken into account. Future work could explore the economic value of using flexibility to solve other technical issues such as voltage control and grid stability.

The relationship between the possible local markets and the intraday market could be further explored. Further research could elaborate on when it would be profitable for the BRP to move towards the local market or bid in the existing intraday market.

The determination of where in the distribution grid there will be a need to make decisions of flexibility use is also out of the scope of this work. Further study is needed to create a methodology that studies the different connecting substations between DSO and TSO and determines where the most issues could be found.

Regarding the regulated market participants, this thesis focuses on providing a thought methodology for the DSO. It is assumed that the TSO already has mechanisms to contract reserves. Nevertheless future research could study the needed evolution of reserves contracting on a TSO level with respect to resources located in the distribution system.

Uncertainty in this thesis is modeled through the use of scenarios. It is assumed that all flexibility will be available as predicted. A deeper study of uncertainty in flexibility contracting is relevant for the DSO when flexibility is meant to substitute grid investment. The DSO faces an unknown value at risk in case of non-compliance of the available resources.

Chapter 7 presents a case where a BRP competes with a DSO for flexibility resources provided by one aggregator. In this case the aggregator is likely to set monopoly prices in the absence of competition on the supply side. The simple case is representative of the rationality of the buyers, an extension of the case to include competition on the supply side would contribute insights to the discussion.

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List of Publications

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